The Province of Alberta

IN THE MATTER OF "THE NATURAL GAS UTILITIES ACT"

—and—

IN THE MATTER OF an Enquiry into Scheme to be adopted for Gathering, Processing and Transmission of Natural Gas in Turner Valley

G. M. BLACKSTOCK, Esq., K.C., *Chairman*

Dr. E. H. BOOMER, F.C.I.C., *Commissioner*

Session:

CALGARY, Alberta March 26th, 1945.

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No.

H-1-1

9.30 A.M.Session.
March 26th, 1945.

MR. JOHNSON: Mr.Chairman and Mr. Commissioner. I have one or two corrections that I would like to draw to your attention in Volume 13, being the transcript of March 21st. The first is on Page 1056, on the nineteenth line, about three-quarters of the way down the page, there appear the words "Cross-section" which is part of Mr. Connell's answer. He said "Across that part in yellow is an orange cross-section" that should read "Cross-hatch".

MR.CHAMBERS: That is also referred to in the question lower down?

MR. JOHNSON: Yes, the same page, six lines from the bottom. The same expression. Page 1059 at line 20, about three-quarters of the way down, at the beginning of the last paragraph on the page, it now reads "That included Okalta 16"; that should read "That excluded Okalta 16". On page 1060, line 21, Mr.Connell's answer is given as "and the last information I had it started to produce water"; it should read " and the last information I had it had not started to produce water."

MR. CHAMBERS: In the fourth line after that where it says "local subdivision it should read "legal subdivision". It should read "Commoil is in the legal subdivision".

MR. CONNELL: It should be "Commoil 3 is in legal subdivision".

MR.HARVIE: That should be Commoil 3 should it?

MR.JOHNSON: Yes. And I have also told the Court Reporter that the spelling of Mr. Connell's middle name is "A-l-l-e-n".

DR.BOOMER: I believe there is an error in Mr.Davies' evidence on Page 997 on Volume 13, the fourth question, "As regards the gas cap that is right, but so far as the crude, the acreage is more." The answer "Yes." The Question "The assigned acreage is more?" A.There are some 120 acres or more."

MR. DAVIES: That is wrong. The acreage is less in the crude area.

DR. BOOMER: The question reads as though it refers to crude area and you answered it as though you were asked about the gas cap area.

MR. DAvies: That is correct.

DR. BOOMER: What is the correction, Mr. McDonald?

THE CHAIRMAN: The word "less" should be there instead of the word "more".

MR. DAVIes: The acreage is less in the crude area.

MR. McDONALD: I think it should be reversed regarding the crude area; that is right so far as the gas cap is concerned.

MR. DAVIES: That is right.

THE CHAIRMAN: It does not make any difference which way you make the correction.

MR. CHAMBERS: "There are some 120 acres or more", does that mean there are that many more acres in the crude than in the gas cap?

MR. FENERTY: Less.

MR. DAVIES: Yes.

MR. HARVIE: Well that question now read "As regards the crude area that is right, but so far as the gas cap, the acreage is more"?

THE CHAIRMAN: There will be the word "less" in there.

MR. McDONALD: There is one further correction, Mr. Chairman, at 1006. At the bottom of the page.

MR. CHAMBERS: 1006?

MR. McDONALD: Yes. It reads "10 billion cubic feet". This should be 10 million cubic feet.

THE CHAIRMAN: "Million" instead of "billion"?

MR. McDONALD: Yes.

MR. DAVIES: Sir, there are a number of other corrections in here that we would like to make, and I would like to have an opportunity of going through it all with Mr. Fenerty.

THE CHAIRMAN: You make them later at any time you wish.

MR. DAvies: Thank you very much, sir.

....

Q GORDON ALLEN CONNELL,

examination by Mr. Chambers continued:-

Q Mr.Connell, when we rose on Wednesday last you were reading from your report, Exhibit 44, and it is my recollection that you had just got to the bottom of Page 2.

THE CHAIRMAN: Top of Page 5.

WITNESS: Top of Page 5.

Q MR. CHAMBERS: Yes. And will you proceed with your report?

A Just to pick up the threads of this report, on Wednesday I stated that for the crude oil wells if the wells were produced down to 10 barrels per well per day, or 75 pounds per square inch, whichever was the lateral of the two, I estimated that 290 billion cubic feet would be produced by those wells to that limit. However, if these wells were just produced to 10 barrels per well per day, irrespective of pressure, that is, the operating tubing pressure, I estimated that 187 billion cubic feet would be produced from the wells in the crude oil area as of January 1st, 1944. And for the gas cap I estimated that 301 billion cubic feet could be produced for the gas cap if the gas cap were produced down to 100 pounds per square inch weighted average bottom hole pressure. Now that is not my estimate o the total gas in the field and does not estimate what gas I expect that will be produced. That is the estimate that I made of the gas you might expect to be produced if the wells were produced down to those limits. However, as it will be developed in Mr.

Stevens-Guille's report, it will not be economical to produce or to gather the gas that these wills will produce down to those limits, and, as will be developed later, it may not be economical to produce some of that gas even though it is economical to gather it.

Factors Affecting Availability of Crude Oil Well Gas.

The amount of the gas produced which will be available to the system is dependent on the gas gathering line pressure and well operating pressure. Liquid loading due to either water intrusion or to decrease in bottom hole pressure will reduce the operating tubing pressure and, if the gas gathering line pressure is too high to allow the well to be produced economically, it would be necessary to flare this gas, thus reducing the net amount of gas available to the market. This effect has already been noticed at a number of wells. For example, Northwest Hudson's Bay No. 4, Northwest Hudson's Bay No. 8, Royalite Canadian No. 1 and Royalite No. 31 all load up and die against a gas gathering line pressure of 160 to 175 pounds per square inch, and in order to produce these economically, it will be necessary to produce these wells at a lower pressure, in the near future. To conserve this gas, these wells could be tied into the British American low pressure gas gathering system. However, for other similar wells where no low pressure gas gathering system is available, and where insufficient increase in marketable reserves would be obtained to justify the cost of installing additional compressors to pick up this gas, the gas would have to be flared.

The loss of marketable reserves due to liquid loading is at present an indeterminate quantity. This effect is at present apparent only in the deeper wells, but as the bottom hole pressures of the wells decline, it will tend to affect the wells higher up the structure, so that, after additional information is obtained, it may be necessary to revise the estimates of economic marketable reserves downward.

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I think this liquid load factor will have probably a greater effect on my estimate later on of 10 barrels per well per day or 75 pounds average pressure because the bottom hole pressure will be lower than if the well were just carried down to 10 barrels per well per day. It may be that we will have equipment to eliminate this difficulty although I do not think we will be able to eliminate it entirely and we may still get to the point where they are not able to get into the gas gathering line.

The method of producing wells will also affect the available reserves. It may be found that at certain crude oil wells a marked increase in gas/oil ratio may be obtained by operating at a pressure lower than the gas gathering line pressure. Actually this would represent conservation of reservoir energy and increase the amount of oil recovered. This practice would decrease the marketable reserves. I have one example of that here in the case of Royalite 70 well. In January 1944, the daily average production was 82.3 barrels and the gas/oil ratio 3198. At that time the separator pressure was 25 pounds and the tubing pressure was 185 pounds. From February 8th to February 28th the well produced into the gas gathering line operating at a tubing pressure of 300 pounds and a separator pressure of 269 pounds and the average oil production was reduced to 46.9 barrels per day and the gas/oil ratio increased from 3198 to 3835. That is the average gas/oil ratio showed an increase of 637 cubic feet per barrel.

Q MR. BLANCHARD: Where is that well?

A That is in Section 22, township 20, range 3, W of the 5th.

Q That is hooked into the line is it?

A The gas gathering line is hooked into that battery but we cannot produce that well into the gas gathering line.

Q MR. McDONALD: What is the legal subdivision?

A Legal subdivision 11.

Q DR. BOOMER: Is that well still producing into the gas gathering line?

A No, it is not. That well is not produced into the gas gathering line at the present time. We attempted to produce it into the gas gathering line but the pressure during February - I have some figures here - from February 10th to 13th, the well produced 76 barrels at a gas/oil ratio of 4132 cubic feet per barrel, the separator pressure was 20 pounds. We attempted to build that well up to a higher pressure. From February 14th to 17th, the average production was only 11 barrels per day and the gas/oil ratio was 14,133 cubic feet per barrel and the average operating pressure was 200 pounds and the average separator pressure 155 pounds. In a well like that it would not be economical to produce it to the gas gathering line though however when the gas gathering line pressure is decreased we will attempt to produce it into that line again and see how it affects the gas/oil ratio on production.

Q DR. BOOMER: Has the gas/oil ratio backed

down?

A The gas/oil ratio at the end of the month was 3808 and the oil production 78 barrels.

Q MR. McDONALD: What were the pressures at the end of the month?

A Casing pressure 351; separator pressure was 20 and tubing pressure slightly above that 20, probably about 30 or 35 pounds. Another example of that here is Foothills 18.

Q MR. CHAMBERS: Where is that well?

A It is in section 9, township 21, range 3, W of the 5th.

Q Will you point it out again?

A Right there. It is in legal subdivision 8, section 9, township 21, range 3, West of the 5th. February 1st to 17th that well produced an average of 254 barrels and the gas/oil ratio was 1300 cubic feet per barrel. Average tubing pressure was 301 and average separator pressure 202. That well was turned into the gas gathering line on February 18th and from February 20th to February 28th the average production was 149 barrels, the gas flow 263, the gas/oil ratio 1765, tubing pressure 379, separator pressure 328. We have left that well in the line. We hope that the gas gathering line pressure will be reduced just to conserve that gas and let it into the line. At other wells it may be found that, for convenience of operation, a reduction in gas/oil ratio, or conservation of gas, it may be economical to produce against the gas gathering line pressure even though the oil production rate is reduced below the allowaable. This would increase the marketable reserves.

Both the amount of gas produced and the marketable reserves will be affected by the time that wells are abandoned. The abandonment time will be dependent on the economic limit to which a well can be produced. Changing economic conditions could alter this point of abandonment and this will show some effect on the marketable gas reserves. That will be considerably affected by the amount of gas and the amount of oil an individual well will produce and also the price of gas and oil and the cost of operation. If the price of gas or oil were increased, the well could produce to a lower production rate. That is also true if the cost of operation of these wells were reduced. It may be that in the later days of the project it will be necessary to go to unit operations and groups of wells may be operated by an independent company or one of the other operating companies. So that is why we say that our estimate for the amount of gas that will be produced from the crude oil area will lie somewhere between 187 and the 290. The time that wells are abandoned will also depend on the Board's decision on the time they will allow a well to abandon. If a well is still able to produce a considerable amount of gas, even at a low oil production such as 10 barrels of oil per day per well, it is possible that that well could be kept on as a gas well and in fact it would be sounder to keep those wells on as gas wells than to drill new wells in the gas cap.

Method Used in Estimating Gas Reserves of Gas Cap Wells.

Dr. George Granger Brown's method of calculating the gas reserves as outlined in his paper "Deviation of Natural Gas from Ideal Gas Laws" was used to calculate gas reserves from the gas cap wells. That is the same method as used by Dr. Katz in making his estimate for the gas cap. Bottom hole pressures at mean formational datums for each well in the field were calculated from the annual 24 hour closed pressure tests conducted by the Petroleum and Natural Gas Division of the Department of Lands and Mines or the Conservation Board. Prior to 1934 a considerable portion of the gas produced was either estimated or measured periodically using a pitot tube and, therefore, the quantities produced are questionable. I do not mean that those estimates are unreasonable but they are not as accurate as to quantitites as measured by meters. I think Mr. Beach told us that metering in general started in October 1933. In addition, prior to 1934, there was insufficient control over the pressures at the extreme south end of the field, as only two wells were completed in the British American plant area prior to the closed pressure tests in September 1933. Those were Merland 1 and Freehold Mar jon 1. Merland 1 is in section 27, township 18, range 2, W of the 5th, and Freehold Marjon is in section 28 of the same township, 18, range 2, W of the 5th. Therefore bottom hole pressure isograph - sometimes known as isobaric - maps for the gas cap area were constructed for each year from 1934 to 1944. Photostats of these isographs are given in Appendix B. I think Mr. Davis explained the method

of calculating the weighted average pressures using these isobaric maps. From these isographs weighted average bottom hole pressures were calculated and these bottom hole pressures were plotted against cumulative gas production for the gas cap wells in the Royalite District #1, Sterling Pacific Area, Gas and Oil Products Plant Area (including East Crests and Homestead), the British American Plant area and the entire gas cap area. Those are the graphs that appear in Appendix"A", graphs number 1 to 5. I will have occasion to refer to some of those graphs later.

The Royalite District #1 gas cap extends from the Northern limits of the gas cap immediately North of Foothills 1, South to the Southern boundary of section 9, township 19, range 2, W of the 5th, excluding the East Crests and Homestead acreage. That is to say Royalite District #1 gas cap starts here at the very Northern tip of the gas cap and extends down to just North of the Gas and Oil Products plant, excluding Homestead and East Crests acreage in section 16, township 19, range 2, W of the 5th. The Gas and Oil Products plant area gas cap is the gas cap area in sections 4, 5,and 16, township 19, range 2, W of the 5th. That is this area in here and the East Crests and Homestead areas.

The Sterling Pacific area is the section of the gas cap in legal subdivision 6 to 16, inclusive of section 33, township 18, range 2, W of the 5th. That would be all this Southerly legal subdivisions in

section 33, township 18, range 2, W of the 5th. The British American gas cap is considered to be all of the gas cap area south of the Sterling Pacific gas cap area.

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Q MR. CHAMBERS: Would you pause there for a moment, the graphs you refer to there at the beginning of that paragraph, those are one to five?

A Those are graphs one to five.in appendix A.

From the graphs of weighted bottom hole pressures v.cumulative gas production it was noted that the declines in the 24 hour bottom hole pressures were rapid when the gas withdrawal rates were high, but, after the withdrawal rates were decreased, the decline in the 24 hour bottom hole pressures, per unit volume of gas withdrawn, decreased. This effect was due to the relatively low permeability of the limestone. However this effect in most of the gas cap wells is not nearly as marked as it is in the case of the crude oil wells. The 24 hour bottom hole pressures at most gas cap wells, as calculated from the 24 hour closed pressures, approach the reservoir pressures more closely than do the 24 hour bottom hole pressures at most crude oil wells. In an attempt to estimate the approximate percentage increase in pressure from the 24 hour closed pressure to the reservoir pressure the pressures obtained in 1932, after 24, 48 and 72 hour shut in periods were used. A summary of these pressures is given in Table Vl, page 86.

In the case of some wells, decreases in pressure over the pressure taken 24 hours earlier were noted. These were probably due to inaccurate gauge readings or to well head leaks. At Miracle 3 an abnormal increase in pressure was recorded between the 24 hour and 48 hour closed pressure

tests. Ignoring the pressures at the wells where decreases were recorded and the Miracle 3 pressures, the arithmetical average increase of the 48 hour closed pressures over the 24 hour closed pressures was 1.1%, while the 72 hour pressures recorded an increase of 1.9% over the 24 hour closed pressures. Now that was my attempt to estimate how much the reservoir pressure would be greater than the pressure taken after the 24 hour.

Therefore it was estimated that the reservoir pressure would average at least 5% more than the 24 hour closed pressures in the years when the withdrawal rates were high. As the high withdrawal rates continued in the years 1934 to 1937 for the Royalite gas cap, and 1934 to 1938 for the balance of the field, this percentage would increase. I think that requires a little bit of explanation. My idea there was to take a new well and produce it for say a period of a year at a constant rate. The 24 hour pressure there would be less than the true reservoir pressure. If that well is produced for another year, the 24 hour pressure there would be a greater amount less than the true reservoir pressure, that is the time factor comes in.

Q THE CHAIRMAN: When you say "24 hour pressure" you mean the "24 hour shut-in pressure"?

A The 24 hour closed pressure.

Since the voluntary reduction of the gas cap withdrawals by the Royalite in 1937 and the introduction of gas cap allowables by the Conservation Board in October 1938, and, later, the more drastic reductions under the Brown Plan, the 24 hour closed

pressures tended to approach the reservoir pressures more closely. This is especially true in 1944 when a number of wells were closed in for one or more months prior to the closed pressure tests. During the period between the June 1943 and June 1944 closed pressure tests, less gas cap gas was withdrawn than during any previous year. As can be seen from Table V increases in the weighted average bottom hole pressures were recorded in both the Sterling Pacific and the British American Plant Areas. Part of these increases may have been due to migration of gas from the crude oilwell area. A relatively large drop was recorded in the Gas and Oil Products area. This may have been due either to a slight amount of liquid in these holes or to the rate of production immediately prior to these tests.

I think we might just refer to Table V and also to graph 2.

Q MR. CHAMBERS: That is Table V on page 85?

A Table V on page 85 and graph No. 2 is in appendix A, relative to the No.I gas cap area.

Now between August 1934 and August 1935 the production from the Royalite Gas Cap was 40.5 billion cubic feet and from August 1935 to June 1936 was 37.5 billion cubic feet and for the next year 41.1 and from June 1937 to June 1938 the production was 24 billion.

You will note on graph No.2 that from August 1934 to June 1937 the pressures are increasing rather rapidly. Just as soon as that production rate was decreased the pressure declined at a less rapid rate.

Now that means or signifies that 24 hour closed pressures were close to the reservoir pressure due to the reduction in the withdrawal rate and not necessarily due to migration. A very small amount of that may have been due to migration but as the Royalite gas cap comprises between 75 and 80% of the total gas cap and as there was very little drilling to the West of there, - most of the drilling was West of the Gas and Oil Products, Sterling Pacific and the B.A.Gas Cap Area, that is between 1937 and 1938, I do not think you can attribute the increase in pressure and the decrease in rate of decline of the bottom hole pressures in the gas cap due to the migration of gas. I think it is chiefly due to the decrease in the rate of production.

Q THE CHAIRMAN: And the drilling of wells did not have much effect?

A The drilling of the crude oil wells, yes, Model 1 was completed in 1930, Model 2 in 1933, Model 3 in 1935 and those wells were producing right along from 1935 to 1937, so they had no material effect so far as migration was concerned, so far as the Royalite gas cap area.

The next well completed was Royalite 29 in 1938 and there were no more wells, crude oil wells, completed until 1939 West of the Royalite gas cap area.

Royalite 35 was completed in April 1939 and Argus I was completed in the Fall of 1939, -just let me check that date, -Argus I was completed October 19, 1939.

I have also here some graphs

which we might deal with, as to the migration. Do you wish to do that now, Mr. Chambers?

MR. CHAMBERS: Yes, we may as well put them in now.

GRAPH PRODUCED HERE MARKED AS EXHIBIT 46.

Q THE CHAIRMAN: How would you describe those exhibits Mr. Connell?

A We could describe those as "Pressure Cross-Sections"

Q How many?

A Six all together.

Q MR. HARVIE: What do you call those, Mr. Connell?

A They are actually pressure cross-sections in the limestone.

In preparing these graphs we made a cross-section of the limestone at right angles to the strike of the structure and we converted the pressures, the closed pressures on the gas cap, the bottom hole pressure on the crude oil, to a datum of 2200 feet below sea level, that is to say in that one of the deep wells, Sovereign and Highwood Sarcee I, we calculated the pressures at 2200 feet below sea level and at Sovereign I, using the top hole pressure obtained in June 1944, closed pressure tests, to a depth of 2200 feet below sea level. For that we used Dr. Brown's graph for converting from top hole to bottom hole pressures. Those graphs were supplied by the Conservation Board.

In the case of the crude oil wells we took the bottom hole pressures and subtracted a pressure equivelent to 331 pounds per sq.inch per 1000

feet from the depth where the bottom hole pressures have been taken to a depth of 2200 feet below sea level.

In the case of Deep Oils No.I there was a built-up pressure test there and the reservoir pressure as calculated was 1285 pounds and we converted it from the 1285 pounds back to 2200 feet below sea level by making an allowance of 1530 times 331 pounds per sq. inch per 1000 feet. 1530 is the depth of the pressure datum to 6200 feet, or rather to 2200 below sea level.

From these graphs it will be seen that the bottom hole pressure from the crude oil wells, Deep Oils No.I, was still considerably higher than the pressure at the same datum in the gas cap and if it was required that differential, to get the small amount of increase in the future even though the gas phase has increased, the differential is not going to be very much greater from the gas cap to the crude oil area, or that condition may not arise at all but if it does arise the differential is going to be very small so I think we can expect only very little migration in the reverse direction.

A Might use a small amount in areas where the permeability is good. I do not think we can expect much in areas, say west of Royalite gas cap, because those areas are between the gas cap and the crude oil area. West of Royalite district one gas cap there is an impermeability zone. I think I can point that out to you on the map. Davies five is impermeable..

Q What is the location of the Davies?

A Davies five is in Section 18, Township 19, Range 2, West of the 5th. A number of these other wells as we go north, Pacific Pete in Section 25, Township 19, Range 3, West of the 5th is also impermeable.. Argus No. 1 is another example. That is in the same section. Royalite Lowery we found to be a very impermeable well. That is in Section 11, Township 20, Range 3, West of the 5th. Both Royalite 56 and 60 we found to have variable permeability. Royalite 56 and 60 are in Section 14, Township 20, Range 3, West of the 5th. In Section 2, Township 20, Range 3, West of the 5th we have obtained better wells so that maybe the permeability may be better in this section, but it is also possible there may be an impermeable zone, say between Okalta 13, which is in Section 36, Township 19, Range 3, West of the 5th. Okalta 13 was a well with low permeability and there may be a low permeability zone extending right through Okalta 13, Royalite Lowery and Royalite 56 and 60 in the north end as illustrated in this graph, Foothills 1 and Royalite 26 and 27 approximately is better so that there is a possibility in that area of some migration, but I do not believe that migration has

been very great in the past and I doubt as the differential decreases, it is doubtful if there be very much in the future. And certainly doubtful if there would be in the reverse direction. There might be a small amount, but I do not believe that amount would be much, therefore I do not believe any great benefit can be obtained by the crude oil wells by storing gas in the gas cap.

THE CHAIRMAN: Is that true of the whole gas cap?

A It is mainly the Royalite gas cap. The permeability is a little better in the south end and there is permeability in Royalite 26 and 27 - is also a little better.

To calculate the pore spaces in each of the four gas cap areas the weighted average bottom hole pressures were increased by 5% for the years 1934, 1935 and 1936. No adjustment was made for the June 1944 pressures. The production for the period August 1934 to June 1944, August 1935 to June 1944 and June 1936 to June 1944, were then used together with the decreases in weighted average bottom hole pressures for the respective periods. These calculations I have given in Table 7. From these pore spaces the gas reserves were calculated to a bottom hole pressure of 100 pounds per square inch as shown in Table 8. It will noted that the calculated gas reserves using the period August 1935 to June 1944 are, in each case, slightly higher than those calculated for the period August 1934 to June 1944. The reserves as calculated for the period June 1936 to June 1944 are, in turn, higher than those calculated for August 1935 to June 1944. For the reason mentioned previously, owing to the continued high withdrawal rates, the August 1934

pressure would approach the true reservoir pressure more closely than would the August 1935 and June 1936 pressures. Therefore the reserves as calculated for the August 1934 to June 1944 period are considered to be closer to the actual reserves. For the Gas and Oil Products Plant gas cap area the reserves were also calculated for the period August 1934 to June 1943 as the June 1944 pressure appeared to be low. This increased the calculated gas reserves for that area from 25.6 to 27.3 billion cubic feet. The latter value was used as the reserves for that area.

Now if I chose not to increase those 1944 pressures at all I would have obtained a reserve for the field as of January 1st, 1944 of 342 billion cubic feet. Using the 5% increase I obtain 301 billion cubic feet. If the increase should have been 10%, the calculated value would be 270 billion cubic feet. I felt that I should use some increase and I thought 10% was high and should have been greater than say 2 or 3% and I used 5% which to me appeared to be the reasonable value. Now the main difference between this method and that used by Dr. Katz, is that in 1944 I used weighted average bottom hole pressures as giving weight to the unassigned acreage as well as the assigned acreage, whereas Dr. Katz only used the assigned acreage. If I had used pressures as Dr. Katz had, the initial pressures, and calculated down, and if I had used Dr. Katz' initial pressure of 2250 as in his first report and used my bottom hole pressures for the field the weighted average being 627 pounds I would have arrived at an estimate

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Dir.Exam. by Mr. Chambers.

down to 100 pounds per square inch and of 291 billion cubic feet as of January 1st, 1944. If I had used 2300 pounds initial pressures I would have arrived at 283 billion cubic feet so that would be a maximum difference of 6% in the two different methods, using the 5% increase for the 1934 or using the initial pressures that Dr. Katz used.

I might say in that regard that Merland 1, which has an elevation of 4274 and pressure of 1885 pounds, I calculated a bottom hole pressure of 2280 pounds per square inch, at 950 feet below sea level. That well had produced some gas to that time so that 2280 might be slightly low, 2300 or 2325 might be something in the correct order.

In Table lV (Page 61) is given a summary of the 24 hour closed pressure tests, calculated bottom hole pressures and cumulative gas productions for the individual gas cap wells, used in constructing the bottom hole pressure isographs. A graph constructed by Dr. Brown and supplied by the Conservation Board was used in converting from top hole pressure to bottom hole pressure at the mean formational datum.

Table V (Page 85) is a summary of the calculated weighted average bottom hole pressures and the cumulative gas production for the four gas cap areas and the entire field.

Graphs of the datumin Table V accompany this report in Appendix A under separate binding. The extrapolation on these graphs are based on the calculated pore spaces for the individual areas.

MR. CHAMBERS: Those words under separate heading, under Section A should be struck out?

A Yes, we later decided to put it in one body. That is to say, referring again to Graph No. 2 for the Royalite district No. 1 gas cap in August 1934 increased the pressure to 5%. From that pressure I calculated how much and knowing the pore spaces as calculated I calculated how much gas should be produced down to 1000, 800, 600, 400, 200, and 100 pounds and that extrapolation shown on there is based on those calculations.

To determine the volume occupied by gas at reservoir conditions a chart constructed by Dr. Brown and issued by the Conservation Board was used.

METHOD USED IN ESTIMATING CAPACITY OF GAS CAP WELLS

In order to determine the time at which peak gas loads could not be met, capacity curves were drawn for individual gas wells or groups of wells. A method similar to that outlined in the U. S. Department of Interior, Bureau of Mines, Monograph 7 "Back Pressure Data on Natural Gas Wells and Their Application to Production Practices" was used. According to the method outlined in that publication, approximate gas capacities for any specified reservoir pressure and flowing bottom hole pressure may be obtained by measuring a series of gas flows, at known reservoir and calculated flowing bottom hole pressures. Plotting the values $P_f^2 - P_s^2$ against the measured volume of gas a fairly good straight line relationship may be obtained on log-log paper. P_f represents the shut in

formation pressure and P_s the sand or flowing bottom hole pressure.

That is to say a gas flow is a function of the differential between the reservoir pressure and flowing bottom hole pressure.

Q MR. CHAMBERS: Pardon me, Mr. Connell, you say at the beginning of that paragraph capacity curves were drawn for individual gas wells or groups of wells. Those are graphs 6 to 75?

A Those are graphs 6 to 75. That is correct.

Owing to the nature of the data available, such curves are, at best, only a rough approximation. However, by plotting the value $P_s^2 - P_w^2$ against measured volumes fairly good curves are obtained. P_s represents the 24 hour closed pressure and P_w the well operating pressure. The values of P_s were increased 5% prior to January 1939 as the new Conservation Board's gas allowables first became effective in October 1938 and the decline in the 24 hour bottom hole pressures per unit volume of gas produced decreased due to the lower withdrawal rates.

I have already explained why I have used the increase of 5%.

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The gas flows at wells which have been shut in for long periods are high shortly after they are opened up as the pressure around the bore hole will be close to the true reservoir pressure. If a well is operated steadily for a long period the pressure for some distance around the bore hole is decreased. Therefore, volumes and operating pressures were, as far as possible, selected for periods when the wells had been operating for long periods.

That is to say there is no point in taking gas flows immediately after wells have been opened up after long shutins, and I thought it best to take gas flows under actual operating conditions, which gives us a better picture of what the wells are capable of and the capacity of the wells.

This was not always possible so that in making the extrapolation an allowance was made where the volumes were considered to be too high. This was particularly the case in the more recent years since the withdrawal rates had been reduced and a number of wells shut in for a good portion of the year. For example, Foothills 2 was only operated 144 days in 1942 and 215 days in 1943 and Royalite 14 was only operated 70 days in 1942 and 161 days in 1943.

There is another point there, some of these wells may be operated at restricted rates and just used for control. Royalite 17 is one example that is used for control. You may operate it with considerable back pressure so that flows obtained by that well arenot too reliable for this purpose unless wells are operated

steadily for a considerable period of time.

Therefore, volumes obtained were considered to be higher than if the wells were produced steadily. Where the points obtained in the earlier years appeared to be out of line with the balance of the points, they were ignored in the extrapolations as both the operating pressures and volumes are questionable. In the more recent years when a large number of wells were operating wide open to the gas gathering lines both the operating pressures and volumes were more reliable.

The data given in Table IX was plotted for all wells which are, or were at one time, operated by Royalite and for which sufficient data were available. For Royalite operated wells where insufficient data were available, capacities were estimated using the ratio of the June 1940 flows at 2/3 closed pressures to the flows at 2/3 closed pressure of the adjoining well or wells and the capacity curve for the adjoining well or wells. For example the total flows at 2/3 closed pressure for the McLeod 1, 2 and 5 group was 6,060 Mcf. per day as against 5,400 Mcf. per day for McLeod 4. Therefore to obtain capacities for the McLeod 1, 2 and 5 group the values of $Ps^2 - Pw^2$ for McLeod were increased 10%.

I obtained that by using the factor $\frac{6060}{5400}$. That is actually an increase of 12% rounded off to 10. From the extrapolations of the curves gas volumes at $Ps^2 - Pw^2$ values of 5, 10, 50, 100, 500 and 1000 M lbs. per square inch squared, were obtained and

from these totals as shown in Table. X, page 102, a family curve was drawn for Royalite District No. 1 gas cap wells and for Sterling Pacific 1, 2 and 3.

Q MR. CHAMBERS: Those are Graphs 6 and 7?

A Royalite District is Graph 6 and Sterling Pacific is Graph 7.

In order to make an estimate of the capacities of wells in the Gas and Oil Products and British American Plant areas, on which operating data were not readily available, an average capacity curve for wells that are, or were at one time, operated by Royalite, from the Maylands south to C.& E. Longview No. 1, was plotted.

Q That is Graph No. 8?

A Yes. A comparison between the gas volumes at $Ps^2 - Pw^2$ values as obtained in the June 1940 flows at 2/3 closed pressure tests and the volume at the same $Ps^2 - Pw^2$ value from the graph was made for the same groups of wells and are shown in Table IX. The gas volumes from the capacity graphs averaged 37% of the volumes obtained in the June 1940 volume tests. Using this percentage of the June 1940 gas volumes at 2/3 closed pressures for the wells in the Gas and Oil Products and British American Plant areas, and the $Ps^2 - Pw^2$ value as obtained in the 1940 volume tests, an extrapolation was drawn for each well in these areas, parallel to the average curve obtained for the Mayland-Longview group. Family curves were then drawn for the Gas and Oil Products and British American Plant areas. These data were also given in Table IX.

The data for these graphs was given in Table IX

page 100 and 101. That is to say we had reasonably good data on most of the Royalite operated wells, but similar data was not available for most of the wells in the B.A. and G.O.P. areas. So I used the data that waz available for the wells from Maylands South to C.& E. Longview, and thenobtain a proportion by $Ps^2 - Pw^2$ values by 1940 closed pressure tests, and that works out to 37%. In turn I used those values to calculate the $Ps^2 - Pw^2$ for the Gas Oil Products and the B.A. Plants area.

The family curve for the Royalite District No. 1 wells varies slightly from a straight line and was drawn through the points as calculated. However, in the case of the average curve for the Maylands-Longview group, which also varied slightly from a straight line, a straight line was used as it is recognized that the volumes at 2/3 closed pressure may vary considerably depending on how the well was produced immédiately prior to the tests and whether any liquid was produced during the actual flow tests. That is to say, those values at 2/3 closed pressure are not too reliable. That is the only information I have to go on for those wells.

In Table X is given a summary of the data used is constructing the family curves for the four gas cap areas.

Individual well and family gas capacity graphs are included in Appendix A. That is Graphs 6 and 75.

For convenience in referring to approximate gas flows at various bottom hole or top hole shut in pressures and well operating pressures the data as given in Table IX were calculated from the family curves for the four gas cap areas.

G.A.Connell,
Dir.Ex. by Mr.Chambers.

That is on Page 104.

Q That is Table XI. You said IX.

A Table XI, pardon me.

I then constructed this Table XI for convenience in estimating gas capacities in four different gas cap areas. That is to say if the weighted bottom hole pressure for the Royalite District No. 1 gas area was 400 pounds and the average well operating pressure was 200 pounds we might expect a gas capacity of those wells of approximately 69 million cubic feet per day.

In using the family gas capacity curves weighted average bottom hole pressures may be obtained by a knowledge of the estimated cumulative gas production and reference to the curves "Weighted Bottom Hole Pressure vs. Cumulative Gas Production," Appendix A. Those are graphs 1 and 7. Knowing the weighted average bottom hole pressure and the average main formational depth, at which top hole pressure may be obtained by the use of a graph constructed by Dr. Brown. From the top hole and the well operating pressure a $Ps^2 - Pw^2$ value may be obtained and by reference to the family gas capacity graph for Royalite District No. 1, Appendix A, that is Graph 2, a maximum capacity gas flow may be obtained. For example, for the Royalite District No. 1 gas cap area when the net cumulative gas production is 906 billion cubic feet, the calculated weighted average bottom hole pressure would be 400 pounds per square inch. Using an average mean formational depth of 5,200 feet the calculated weighted average top hole pressure wouldbe 345 pounds per square inch. For an average well operating pressure of

100 pounds per square inch.

$$Ps^2 - Pw^2 = 345^2 - 100^2$$

which would be 109 M (lbs. per square inch)^2.
From the family gas capacity graph for Royalite District No. 1 the gas volume at this value of $Ps^2 - Pw^2$ would be 90,000 Mcf. per day.

As the gas cap wells capacity will probably decrease if all wells were operated at one time, as some wells will affect others, together with the probability that gas volumes will tend to be affected to a greater extent by liquid loading as the bottom hole pressure declines, it is recommended that the gas volumes obtained from the capacity graphs be used only for peak loads of short duration, say one week or less. For peak loads of longer duration it would, in my opinion, be advisable to reduce the gas volumes as obtained from graphs by 10%.

Liquid loading of wells will tend to reduce the capacity of wells as the bottom hole pressures decrease, and, if the liquid is not cleared from the hole regularly, may kill the well. The removal of this liquid could be facilitated by installing a string of macaroni tubing in the wells. We usually consider macaroni tubing about an inch and a quarter tubing, but it might be necessary to use a larger size up to two inch tubing, so the loss due to friction might not be too great. However, this procedure may or may not prove to be economically feasible, depending on the increase in marketable reserves liable to be obtained and the cost of installing the tubing.

Method Used in Estimating Gas Cap Allowables.

For the calculation of sharing positions by Mr. Stevens-Guille, it was necessary to make an approximation of allowables. Using the weighted average bottom hole pressures for the four gas cap areas in June 1944 and the estimated allowables as obtained from Mr.Stevens-Guille, an equivalent acreage factor was calculated. The weighted average bottom hole pressure at any time for each of the four gas cap areas may be calculated by estimating the cumulative gas production and referring to the graphs for Weighted Bottom Hole Pressure v. Cumulative Gas Production in Appendix A, Graphs Nos. 2 to 5. The allowable may then be calculated for any area using the Conservation Board's graph for calculating gas allowables. The data used in calculating the equivalent acreages are given in Table XIII, That is on Page 110.

Graphs for calculated allowables vs. weighted average bottom hole pressures are given in Graphs Nos. 76 to 79, Appendix A. Two of those graphs were revised and I believe those have been distributed. The revised graphs are 78a for the Gas & Oil Products, and 79a for the B.A.

A summary of the Petroleum Production from Turner Valley to the end of 1944 is given in Table XII. There are some corrections we would like to make in that Table XII.

Q Page 108?

A Page 108.

This is for testing the 1944 production figures as it was necessary to estimate those at the time this report was made up. Crude oil from the limestone wells in barrels for 1944 should read 7,854,827.

MR. CHAMBERS: That is the second last figure in the second column.

A That is right. In place of 7,847,119 it should be 7,854,827. That will change the total to 59,336,501. Naptha for 1944 should read 20,009 in place of 30,109, giving a total of 8,865,778. Gas from shallow crude wells in 1943 is wrong. That should read 57,789.

Q That is instead of 45,789?

A That is in place of 45,789 and the total is 9,485,695. Gas from the limestone oil wells in . . . . .

THE CHAIRMAN: Your correction in 1943 is 57,789?

A Yes, there is an error in the recording.

Q And the total?

A The total is 9,485,695. That is 12 million more. 1944 gas from the limestone oil wells, 30,589,005.

Q MR. CHAMBERS: That is instead of?

A In place of 30,574,250, making a total of 209,190,525.

Q That is instead of which figure.

A Gas from the limestone oil wells should be 30,589,005.

Q And that is in substitution for what figure?

A 30,574,250. That makes a total of 209,190,525. Gas from limestone gas wells in place of 10,711,815 it should be 10,755,057 making a total of 1,112,115,129.

Making those same corrections for the tables on page 109, the grand total should be 73,655,288 in place of 73,657,680. In the other case the grand total should be 1,330,791,349 in place of 1,330,721,352. Those figures will differ slightly from the Conservation Board's as I have considered all the production from the 10 wells, that is Brown 1, B. & B. 1, Firestone, Foundation, Monarch, Mercury Royalties, Westflank 2 and Westflank 3, Westside 1, Okalta 7, transferred to the gas cap wells classification from the crude oil wells classification in January 1943. I have included all those crude oil wells where the Conservation Board includes part of the production from those wells as gas cap wells.

MR. CHAMBERS: Now turning back to pages 59 and 60, just to bring that data up to date. At that time you made an estimate of future drilling for 1944 and 1945. Perhaps so far as 1944 is concerned and 1945 down to date, you can tell us what drilling has taken place there.

A All those wells in 1944 were completed in 1944 as shown. Royalite 77 has been completed. Foothills 20 is completed. Royalite 78 is completed. Pacific Pete 8 is drilling. Royalite 81 drilling. Royalite Lowery 2 drilling. Federated, that is Imperial Federated, is drilling. Royalite 80 and Foothills 21 and 22 are all drilling.

Q Mr. Connell, you were present the other day when I asked Dr. Katz to assume certain facts concerning

Royalite 77 and one or two other wells. For the purposes of the record I think you have the information and I would like you to give it to me. What I refer to is in Volume 10, page 704 of the transcript. Royalite number 77, when was that completed Mr. Connell?

A Royalite 77 was completed January 3, 1945.

Q Where is it located?

A In Legal Subdivision 1 of section 2, township 20, range 3, W of the 5th.

Q What was the casing pressure?

A On January 8th, the well produced 463 barrels gas/oil ratio 1108 cubic feet per barrel. The casing pressure at that time was 1600 pounds. Therefore I concluded from that the pressure at 2200 feet below sea level would have been at least 2000 pounds. It is quite possible it may have been more.

Q What was the closest gas cap well to that Royalite 37?

A Okalta 1 was the closest gas cap well.

Q And the top hole pressure of Okalta 1 on June, 1944 was what?

A 488 pounds, calculated pressure at 2200 feet below sea level was 581 pounds.

Q And then in volume 10, page 706, Mr. Blanchard, I dealt with Arrow No. 1.well. What is the location of that, Mr. Connell?

A Arrow No. 1, legal subdivision 16, section 13, township 19, range 3, W of the 5th.

Q When was that well completed Mr. Connell?

A I believe it was March or April 1940.

Q How far is it West of the gas cap?

A Approximately a mile and a quarter from the gas cap.

Q And what about the pressure, the reservoir pressure there in May 1940, I think it was, I asked about.

A May 1940 that is estimated reservoir pressure of 2740 pounds and converting that back to 2200 feet below sea level, using 331 pounds per square inch calculated density of oil column, a calculated pressure 2295 pounds. That figure you gave Dr. Katz was 300 pounds in place of 331 for the calculated density of oil column.

Q There was another one I asked about, A.P. Con. No. 2, give us the location of that will you please?

A A.P.Con. is in section 6, township 19, range 2, W of the 5th, and that is about a mile and a half distant from the Arrow 1.

Q Yes.

A In June 1940, the top hole pressure was 432 pounds per square inch, calculated pressure at 2200 feet below sea level, 517 pounds per square inch.

Q Have you any record there of when that well was completed?

A Completed June 10th, 1930.

Q Now Mr. Connell, those are the only questions I have to ask you. Is there anything else you want to add? If so, you can.

A That is all I have at the present time.

THE CHAIRMAN: We will have an adjournment of five minutes.

(After short adjournment)

Q MR. CHAMBERS: (to Mr. Connell) Mr. Connell, I wonder if you would check again so that we would have it on the record, the location of that A. P. Con. well?

A Section 5 -20 -19 -2 -5.

Q MR. MCDONALD: Which legal subdivision?

A Legal subdivision 2.

Q MR. CHAMBERS: Did you say "Legal Subdivision 2"?

A No, pardon me, legal subdivision 5 of section 20,township 19 range 2 West of the fifth.

CROSS EXAMINATION BY MR. FENERTY:

Q Mr. Connell, in looking over your figures, Table 9, beginning at page 91 and continuing through, I gather that the closed-in pressure in the gas cap in the Home area, section 20, township 19, would approximate roughly 400 pounds per sq. inch top hole pressure, would that be in the neighbourhood of the figure, have you made any analysis of that?

A Do you mean, recent pressures?

Q Shut-in pressures?

THE CHAIRMAN: What page is that Mr. Fenerty?

MR. FENERTY: Page 93. It shows Home No.I,2, 3,4, Calmont and so on, shut-in pressure 520, 475, 420 there; what I want to get at is are you in a position to give me an approximate average shut-in pressure of the wells in the gas cap in the Home area, section 20?

A You will obtain that from Table lV, page 64. It would be approximately 400 pounds in 1944.

Q And in the area South of section 20, would it be approximately the same figure, 400 pounds?

A You are referring to top hole pressure, are you?

Q Yes, top hole pressure?

A Lowery Pete top hole pressure in June 1944 was 389 pounds and the Mayland group, Mayland 1, 398; 2, 432; 3 - 504 and 6 -442. Is that the section you are referring to?

Q Yes, and now I note on page 9:

"Using an average mean formational depth of 5,200 feet the calculated weighted average top hole pressure would be 345 pounds per sq. inch"

Have you made any estimate or are you in a position now to make any estimate as to the amount of gas which would be left in the formation when the pressure in those wells reaches that figure 345 pounds per sq. inch?

A Do you mean for each individual well?

Q I beg your pardon?

A Do you mean for each individual well?

Q No, I mean the approximate total, what proportion or percentage of the gas in the gas cap for instance?

A Well for the four different areas, say the Royalite DistrictI,The Gas and Oil Products, Sterling Pacific and the B.A. area, we have given graphs, graphs 2 to 5, of bottom hole pressures, accumulated production and in the bottom hole pressure from that you can estimate the amount of gas which would be left in the formation, which would be left down to 100 pounds or any pressure you desire. You can pick it straight off

these graphs.

Q Then on page 9 of your report dealing with liquid loading, you suggest a possible reduction of 10% in volume?

A That is right.

Q Due to liquid loading?

A That is right. That is not necessarily due to liquid loading. Some of that liquid loading which has taken place in the past is included in these graphs. I took actually the two operating conditions. I did not take the gas flow immediately after the well was blown. I took it over possibly several flows. I can illustrate that to you. Take Delhousie 7 June 1943 I used the first twenty days of the month to obtain that average of 1110 M.C.F. per day. Now that was a well, the well was pulled down on the first of June 1943 and the following day it produced 1312 M.C.F. and that dropped to 350 M.C.F. on the fourth. The well was pulled down on the fifth and on the sixth produced 1295 and on the eighth the volume was 446 and it was pulled down on the ninth and the fourteenth and the seventeenth.

Q Now is it possible due to conditions that might exist from time to time, that that factor, that is the 10% for liquid loading, might be increased perhaps as high as 20%?

A It is possible. We are going to attempt to see what equipment we can use to eliminate that factor but it is possible to increase that, but that is the factor that I used and I thought it was a reasonable correction factor.

Q And on page 9 of your report you give your Royalite district No.I, the gas volume would be 90 million cubic feet per day?

A Yes.

Q Now that would be subject to your 10% reduction?

A That is over a time greater than one week. The peak load only lasts for a short while and we thought we might use those curves. If the peak load is of long duration, I did think it should be reduced some.

Q But that 90 million feet would be subject to say your 10% for peak load?

A For peak load.

Q Or liquid loading, I say that 90% would be subject to 10% reduction for liquid loading?

A If your peak load lasts longer than say a week.

Q That 10% is on the basis of a continuous withdrawal for a week?

A That is correct.

Q And if it did not last that long, have you any figure?

A We use the figures as shown. There is no correction. Those figures automatically take into account some adjustment for liquid loading.

Q Then we will say in a cold spell, during cold weather, perhaps where we do not get some of our customary Chinooks, where you had your peak loadings for perhaps two or three or four weeks, that would be subject to a deduction of 10% upward we will say to possibly 20%, might it be, for liquid loading?

A Well we will say "10% upward".

Q You have taken the figure of 10% and you say under certain conditions it could, - you do not think it would, might go as high as 20% reduction for liquid loading.

A You do not know just what effect this liquid loading will have but that factor is what we used and I think it is a reasonable one.

Q You think the 10% is the reasonable average?

A Yes.

Q Then we will take your 10%, - assuming that you have a condition where liquid loading would come to pass, you have 10% off 90 million for liquid loading, have you not, which is available for peak loading?

A Yes, that is a peak loading of long duration, a longer duration than one week.

Q Yes, if you have one of these cold spells for some considerable time?

A Yes.

Q And that is wet gas?

A That is wet gas.

Q Then would it be fair to say a factor of approximately 18% further reduction?

A I think you are getting into a question for Mr. Stevens-Guille.

Q You have some information from his reports on that, I believe that is how it worked out?

A I thought he used 15%.

Q 15% was it, I thought it was 18%?

MR. STEVENS-GUILLE: 17½% I think.

THE WITNESS: Yes 17½%.

Q MR. FENERTY: 17½%, I see. I do not suppose you worked it out but according to my arithmetic that reduces your peak supply available or supply available

where you have to draw on your gas cap for more than one week, so that you have this liquid loading factor and you convert it into something in the neighbourhood of over 66 million cubic feet a day?

A That is for just the Royalite district I gas cap.

(Go to page 1116)

Q Yes. Now you have been working on the basis of 345 pounds pressure. By the time that pressure is reduced to 220 pounds, would that reduction have any effect on the liquid loading situation, first of all?

A It may have.

Q It might increase that more than 10% for a period of time?

A Unless we find equipment to eliminate it.

Q And I gather from your Table on Page 104, that with pressure of 345 pounds as compared to 220 pounds you would have a drop in production, possible production, from that gas cap from 90 million to 38 million?

A That is still against the 100 pounds.

Q Yes.

A 220 pounds top hole pressure.

Q And that might be subject to some further reduction if the liquid loading factor increases beyond 10%?

A That is correct.
As I say these curves take part of the liquid loading into effect. If the liquid loading is considerably greater in the future, of course, it would reduce it, but we may be able to eliminate that.

Q Now are you in a position to hazard -I won't say a guess - but a deduction as to the percentage of the total gas reserves in the gas cap which might remain in the gas cap at the time when the top hole pressure reaches the 220 pounds?

A That would be approximately 250 pounds bottom hole pressure and so there is according to my Graph No. 1 for the Turner Valley gas cap, there would be 1320 billion

cubic feet produced down to 250 pounds. That would leave approximately 80 billion cubic feet to 100 pounds between 250 and 100.

Q Going back to that table on Page 104, and this figure that I mentioned a while ago, the 38 million cubic feet a day at the 220 pounds, that is subject to the 10% deduction for liquid loading in the event?

A That is not only liquid loading, it is also wells affecting one another when they produce steadily.

Q Yes, that is all wet gas and it has further to be converted into dry gas?

A That is right.

Q Which brings it to about 18% further deduction according to the figures which you know will be produced here?

A Yes.

Q Thank you.

EXAMINED BY MR. McDONALD:

Q Mr. Connell, you have two estimates as I have it in your submission. Would you say the lesser of the two is a conservative estimate?

A I think the lesser would be conservative and the higher would be too high.

Q It may be optimistic?

A That is right. We feel that the dry gas as calculated on the two different bases. The one will be optimistic and the other one will be conservative.

Q So that in any event taking into account all operating conditions that may arise you feel that the lesser of the two estimates will be realized in the operation of the field?

A I believe so, yes.

Q And that applies to the gas cap?

A That applies, that gas cap figure is down to 100 pounds per square inch in the weighted average bottom hole pressure but we do not consider that the gas cap will be economically produced down to 100 pounds per square inch. That will be dealt with in Mr. Stevens-Guille's report.

Q But on to your 301 billion?

A We do not expect to produce that much.

Q You have a table I think which shows the amount of acreage that you took into account in making your gas cap weighted pressures. Would you refer to that table?

A Do you mean Table Vl where I outlined the areas used in the gas cap?

Q You have a table that says 5,030 acres as being taken into account when making the figures?

MR. CHAMBERS: Is it Page 110 you have in mind?

MR. McDONALD: Yes, table 13, page 110.

A That is calculated equivalent acreage. That is I took the allowables for say the Royalite district 1 and used the June 1944 weighted average bottom hole pressure. I calculated what the equivalent acreage would be for that allowable. That is for the purpose of estimating allowables in the future based on weighted average bottom hole pressures. That is not assigned acreage. That was just used so we could follow the weighted average bottom hole pressures, cumulative production averages and curves and from that estimate what allowables we might expect in 1944.

Q So that the equivalent acreage gives 4495 that is comparable to the figures used by Mr. R. E. Davis 5120 acres, I think it was.

A No this acreage is not comparable to that. That acreage was just for the purpose of estimating future allowables based on weighted average bottom hole pressures. Knowing the present allowable June 1944, weighted average bottom hole pressure we calculated what equivalent acreage you would require using the Conservation Board graph for calculating gas allowables.

Q And that was on the basis of 25 barrels per acre per day reservoir withdrawal?

A That is right.

Q Now if there is an increase in the 25 barrels per acre per day withdrawal, it would be a difference in the calculated equivalent acreage?

A If you increase your 25 barrels per acre per day you would increase your allowable, but you would not increase your calculated equivalent acreage. The allowables would increase and you would have to make adjustments. You get so much per acre on the allowable basis and in making that adjustment you would come back to the same equivalent calculated acreage.

Q Dealing, Mr. Connell, with the capacity of wells to produce, as I read your report you have calculated the capacity of each crude well on the decline curve method?

A That is right.

Q And you have given us the exact production which you expect to obtain from each well?

A Do not expect that each crude well will necessarily

produce that amount. As I pointed out in my report I expect that some will be higher and some will be lower but I hope that it will average out for the whole field to give the answer that we estimated.

Q But looking into the future your estimate is a fair interpretation of what each well will do?

A That is what we attempted to estimate.

Q Now on Page 45, you deal with the estimate of gas production from crude oil wells in the area served by the British American plant. I note that at the end of the Table, Page 47, you deal with Sunburst, 65, you do not give that well any production at all in 1945?

A No it is pointed out in my estimate we made the cut-off for wells at 10 barrels per well per day or 75 pounds per square inch, whichever was the latter of the two and you will see Sunburst in 1944 averaged about 8 barrels per day at pressures of 35 pounds and we left that out of our estimate. I do not know when that well will be abandoned or if they have any intention to do so. That was one of the assumptions we made.

(Go to Page 1121)

Q But that well is still producing?

A That is right.

Q But it may not be very much?

A No, but it is still producing. Our Royalite 32 is in the same category.

Q Could you tell me what the bottom hole pressure of the Sunburst well is now?

A According to the last data I have here, in November, 1944 it had a calculated bottom hole pressure of 624 pounds.

Q It has a bottom hole pressure of 624 pounds?

A Yes.

Q I understand some of the other calculations by some of the other men they would have taken that well down to 250 pounds calculated bottom hole pressure and 300 top hole pressure?

A Well, the economics of producing a well with an oil production rate that low is doubtful. They might be able to produce this well because it could be connected to the B.A. low pressure system, and you might get some revenue from the gas, but there is going to come some time when that well will not be able to produce, and we did not feel it was within our power to estimate the economic limits of each one of these wells. There are so many indeterminate factors that come into the question.

Q Then under the British American gathering system as now installed, the tubing pressure can go down as low as 10 pounds?

A The tubing pressure could not go that low. You would still have to make allowances for your friction loss.

Q How low could it go say with regard to the wells located in that location?

A I imagine between 20 and 25 pounds. Something on that order.

Q 10 pounds pressure at the B.A. Oil Plant?

A Yes, I would estimate 20 to 25 pounds. I do not have any information on that.

Q Now the same comments as to Sunburst apply to Granville, No. 62?

A That is correct.

Q I believe that well is still operating?

A Yes.

Q Would you give me the bottom hole pressure of that, Mr. Connell?

A The 24 hour bottom hole pressure, November 17th, 1944, 493. After twelve days shut in built up to 614 pounds per square inch.

Q Now, Mr. Connell, comparing Granville and Sunburst, would you give me the 1944 gas production of Granville, was it 175 Mcf. per day against 80 Mcf. for Sunburst?

A That is right.

Q Now looking into the future, would you say those wells would continue to produce at about that same ratio, that is for 1945 and 1946, if they last that long?

A The present allowables are 188 and 100 respectively. It would be something in that order, something on that same ratio. The amount of gas that there will be of course depends on the bottom hole pressure and the gas-oil ratio.

Q That is, the allowable is dependent on it?

A Yes, on the 25 barrels per acre per day for withdrawal. That is on the gas-oil ratio and the bottom hole pressure and bottom hole temperature.

Q In making these estimates for '46 and '47 on, did you take into account that factor, the allowable?

A Yes, these graphs are based on actual operation on the basis of wells. That fact would automatically be taken into account on those wells, the increase in liquid and the decrease in oil and the decrease in gas.

Q Now since any changes in the allowable are uniform across all the wells through the field, they would all be affected alike?

A Of course there are a considerable number of wells where the operator has voluntarily reduced below 25 barrels per acre per day, or there are some wells that cannot produce their 25 barrels per acre per day, even if the operating pressure were reduced down to say 25 pounds per square inch.

Q But your decline curve takes that into account?

A For those wells that have been voluntarily reduced that has taken place in the past and so we considered that might take place in the future. I have made no allowance for possible adjustments in the Brown Plan. It is quite possible it may be done, but I did not assume any in making my estimate.

Q Could I trouble you again, Mr. Connell, about the bottom hole pressure of the Sunburst well?

A According to the information that came from the Conservation Board on the 9th of November, 1944, that well had

a bottom hole pressure of 624 pounds calculated to a depth of 6,988 feet.

Q Have you any record whether it was shut in for 14 days or longer?

A That is the 24 hour shut in.

Q That is the 24 hour shut in?

A Yes, according to our records, according to these records.

Q And then on the Granville well it is 493 on a power shut in and built up in 14 days to 614?

A 12 days.

Q In 12 days?

A Yes.

Q What puzzles me is that one well has a bottom hole pressure of 624 pounds and produced only 80 Mcf per day and the other has a bottom hole pressure of 493 and produced twice as much gas, and they are in very close proximity, only a legal subdivision apart.

A This has been obtained from the Conserfation Board as they had it and Granville was 188, Sunburst 100. The Sunburst is on a 20 acre lease.

Q Yes, that might be the information, Mr.Connell, on that, and that might clear it up. Now would your comments as to these two wells apply to each well in the British American area as it goes off production? I have calculated roughly beyond that up to 1952 at least 17 wells are dropped out of your schedule here. Now if the operating conditions are such from your chart that these wells can be maintained in operation, then your estimate of the reserves in the British American

area would be increased, am I right?

A If it was economical to produce those wells. Liquid loading may also become a factor in those wells unless they are able to eliminate that.

Q DR. BOOMER: Mr.Connell, would those wells produce that under blowing down hole pressure?

A You mean after 24 hours bottom hole pressure?

Q Yes?

A I do not believe so, in the dry hole when the bottom hole pressure is taken.

Q And liquid loading?

A Not necessarily. It would flow through a three inch tubing, you would be able to carry that liquid out.

Q At 300 tubing pressure and 200 pounds bottom hole pressure?

A Yes, but that is not the flowing bottom hole pressure.

Q You do not get that?

A You could calculate the flowing bottom hole pressure from the casing pressure provided there is no liquid in the end.

Q MR. McDONALD: Now dealing with the gas cap wells individually, can you make a similar calculation as to the annual or periodic production of the gas cap wells from the charts that you have set up, in, I think it is 6 to 75, or Graphs?

A Well that would entail a considerable amount of work. You would have to draw graphs to Weighted Average Bottom Hole Pressure versus Cumulative Production, and you would have about 19 wells to do that altogether, and I do not consider it too reliable to do it for individual

wells. Some wells may affect one another and the rate of production from the individual wells will affect your calculated pore space. It is much better to do it over a complete area rather than for individual wells.

Q But it could be done for individual wells?

A It could be done but I would not consider it as too reliable.

Q What I have particular reference to is the British American section and the reserve of the gas cap wells in the British American section be calculated along the lines you have indicated?

A It could be calculated but I would not think it would be too reliable, because it all depends on the rate that those wells produce, and how much has been withdrawn from each one of those individual wells. Some gas produced from one well might have come from the area assigned to another well. If one well were shut in and another well produced, the bottom hole pressure in the well that was shut in could be reduced, and that would show no production for that time where the production for the well producing would be greater than it would normally have obtained if both wells had been producing.

Q Would it be as accurate in comparison between well and well as your decline curves used in regard to your crude area, I mean in the decline curve and in the degree of accuracy?

A I doubt that because most crude oil wells are produced regularly, and may only produce a few days a month, but I think the curves to the crude oil wells would be more reliable than it would in making calculations for the

gas cap wells individually.

Q Now dealing with this matter of liquid loading, Mr. Connell, there are some systems of unloading these wells while they are operating, are there not, that could be installed?

A Yes, we have a Baldwin Dresser search pump that we intend to test on one of our wells, Royalite Lowery No. 1, in order to obtain some information towards eliminating this liquid loading. I understand that they have been used in shallow wells in Ontario to eliminate water from the gas wells. They have not been tried in Turner Valley as yet.

Q And if this mechanical means of unloading is successful, that would mean the problem of liquid loading would be mostly overcome.

A Yes. That has still to be seen. We have to experiment along that line before we can determine whether that particular device will work in Turner Valley itself. It is quite possible if that does work it may work for wells which would have dropped their tubing pressure quite low and you might not be able to work that against a high pressure line. That is an experiment that will have to be carried out. We do not know until that is done.

Q Dealing with this question of running crude oil well gas into the line, you mentioned Royalite 70?

A Yes.

Q And I made a note of what you said. The gas/oil ratio increased from the neighborhood of 3198 on one occasion to as high as 14,133, in one test.

A We did not get that well producing into the line.

We started to build it up to get it into the gas gathering line but the well practically stopped producing oil.

Q In your experiment trying to build it up, you did get a gas/oil ratio of 14,133.

A That was the average for 4 days, February 14th. to 17th.

Q And immediately prior to that, under the method of operation you were using prior to that, the gas/oil ratio was closer to 4000?

A That is right.

Q Was that an unusual procedure with a well located where that well is for that to occur?

A That particular well has a very low permeability. There are other wells in the field in which the same thing would be quite true, if you tried to produce them against a gas gathering line pressure. It all depends on what your gas gathering line pressure is. It makes a considerable difference in operating against a 300 pound gas gathering line pressure as against a 10 pound gas gathering line pressure.

Q As soon as sufficient suction pressures are installed in the Madison system No. 1, that well could be brought to production as a gas producer?

A We are making an attempt to reduce the suction of the No. 1 compressor station to get that well into the line. To increase the gas/oil ratio too much, it would not be economical to do that because you would be wasting reservoir energy as far as oil production is concerned.

Q So that to attempt to sell gas from that well would really be wasting gas as far as producing oil is

concerned?

A That is right.

Q Now dealing with that Foothills 18, Mr. Connell, as I understand you Foothills 18 produced 254 barrels with a gas/oil ratio of ?

A 254 barrels and 1300 cubic feet.

Q 1300 cubic feet gas/oil ratio and that was with a tubing pressure of 303 pounds?

A 301 pounds. Call it 300.

Q That well has been put on the gas gathering line?

A Yes.

Q At what tubing pressure?

A The tubing pressure averaged from February 20th to 28th at 379, say 380 pounds.

Q And the production dropped to . . . .

A 149 barrels average from February 20th to 28th.

Q And the gas/oil ratio increased?

A 1765. That gas/oil ratio in March is now coming down and I think it is now reduced to 1200 or 1300 but the production of oil is still down.

Q Foothills 18 is a new well?

A Yes. It was completed last August.

Q Within the year?

A Yes.

Q Would the same trend of operations occur in regard to an older well, take say Alberta Incomes well, Ace Royalties.

A Alberta Incomes well No. 1, you mean?

Q No, Number 2.

A Number 2, I would have to experiment with each well separately. You would expect a decrease in oil production with an increase in tubing pressure.

Q It is a question of economics for each particular well whether you go into the line or not.

A That is right. That is if your gas were worth enough it might be well to put that well into the line. It is a question of economics both of oil and gas. You do not necessarily use that oil production until your gas/oil ratio increases but you may forestall it. Your rate of income would decline.

MR. McDONALD: I have one more point to cover. Do you want me to continue?

THE CHAIRMAN: How long will it take? If you can finish in five or ten minutes we will go on.

MR. McDONALD: I would prefer to go on at 2 o'clock.

THE CHAIRMAN: Very well.

(At this stage the hearing was adjourned until 2 P.M.)

....

2 P.M. Session.

Q MR. McDONALD: Mr. Connell we dealt with the fact that some of the crude oil wells did not produce up to their 25 barrels per acre per day reservoir withdrawal.

A Yes.

Q What is the situation with regard to gas cap wells?

A Southwest Pete 1 is not able to produce its gas cap allowable. We have an allowable of 125 m.c.f. per day. Actually it is entitled to 522 against the present gathering line pressure producing approximately 125 m.c.f. per day. That is the allowable that is issued to that well. Dalhousie 6 is entitled to 469 m.c.f.'s per day but an allowable has not been issued to that well due to the fact that the lateral from the gathering line to it has not been re-connected and no allowable has been issued.

Q Are there any other wells?

A The one Mr. Davies mentioned, Royalite 24. And that is grouped with the Home wells, the Home-Calmont group, so the allowable is taken out of those wells.

Q Will you explain with regard to grouping in the gas cap wells for allowable purposes. How is the allowable arrived at for grouping?

A The bottom hole pressure is calculated for each individual well and there is an assigned acreage to each individual well and from that the allowable is calculated and the allowables for each individual well are totalled and assigned to that group. So we may draw the total allowable from any one or several of that group of wells. It is usually a matter of

convenience of operation that is done.

Q Is it the situation that every one in the group is operating?

A No.

Q At one time?

A Not necessarily.

Q If they were operated at one time could you draw the allowable as fixed from each of the three or four wells and get the same total?

A I do not understand that. If you produced all the wells at one time we could still produce our allowable.

Q Would each well produce its own allowable?

A Not from each individual well necessarily. As I said Royalite 24 is one instance, it probably could not produce its allowable. I do not know of any others that could not produce theirs.

Q What I have in mind is that my understanding of the allowable fixed by the Board for conservation is for each individual well.

A No, we are given group allowables too.

Q But the group allowable is made up of individual allowables for each well.

A That is correct.

Q And if an individual well could not produce its allowable there should be an adjustment made. That is my point.

A Why.

MR. CHAMBERS: You do not expect this witness to decide that question?

MR. McDONALD: No.

A I think that point has been dealt with by the Advisory Board of the Conservation Board. That is probably the point where it should be brought up. I add there is no reason that I see why allowables could not be withdrawn in that total area, even though there may be one or two wells in that group that could not produce their allowable. That is the only well, Southwest Pete 1, that is not produced due to the fact that it cannot be produced and possibly Royalite 24 and Dalhousie 6 for which no allowable has been issued.

DR. BOOMER: I think Mr. McDonald's question as to Royalite 24 should be referred to the Conservation Board.

MR. McDONALD: It is new to me. It is the first I have heard of it.

DR. BOOMER: I thought you were going after that subject

Q MR. McDONALD: What is your opinion, Mr. Connell, as to the future operation of these wells. Will more of them come into this class where they cannot produce their 25 barrels per acre per day?

A You are referring to gas cap wells?

Q Yes, just gas cap.

A We have reduced the suction pressure at the Number 1 compressor station. The capacity of those wells at the same bottom hole pressure would increase. In order to calculate it for each individual well you would have to follow down the drop in bottom hole pressure and the differential between the bottom

hole pressure and the gas gathering line pressure. It is quite possible for several years as the gas gathering line pressure is reduced, the capacity of those wells will increase.

Q That is all.

CROSS-EXAMINATION BY MR. HARVIE:

Q Mr. Connell, you have just mentioned the fact that there is grouping of wells in the gas cap for allowables. Is there a similar practice in the field as far as the grouping of crude oil wells for their allowables?

A There has been some transference of allowables. The allowable from B. & B. was transferred to Threepoint. That is the only one I know.

Q That is from B. & B. to Threepoint?

A From B. & B. to Threepoint, yes.

Q That is the only one you know of?

A That is the only one I know of in the crude oil area.

Q I refer you to Exhibit 44 which is your report M-1 on page 52, which is Table 2A. I want to just make certain that I understand how this table is compiled. It is a summary of estimates of gas production to an operating tubing pressure of 75 pounds per square inch or an oil production rate of 10 barrels per day. Then you give figures for the years, on the first page, 1944 to 1953 by areas, such as Madison Compressor Station No. 1 and No. 3, and G. & O. P. area and British American area and the totals. Coming down to the item of daily average in the British American oil area for the year 1944,

I note that a figure of 17-odd million per day is used. Just what figure is that? Is that a Conservation Board figure or is that one arrived at from your records?

A No, that is arrived at from our decline curves. We had production figures up to the end of November to arrive at that and then just made an estimate for December.

Q Am I right in saying that is actual figures for 11 months?

A It is fairly close to actual figures. It is partially estimated.

Q Then you come to the same item, daily average for the year 1945 and you have a figure of 16-odd million per day. Just how do you arrive at that?

A Those figures are arrived at by taking an extrapolation that I made for my decline curves and taking the average gas production per well at the mid-year, that is in the month of June and totalling them up for the entire year and I arrived at that total of 16,235 m.c.f.'s per day.

Q Referring back to the 1944 figure of 17 million odd per day, I gather that is the figure of the actual production and estimated production for that whole area for the year 1944.

A That is the whole area. That also includes wells that are not connected to your plant. Just wells in that area. In Table 1 you can follow through and find out which was considered to be in the B. A. Plant area.

Q Yes, I have that. That would be from both the crude

and the gas cap?

A No, that is just for the crude oil area.

Q Just for the crude oil area?

A Yes.

Q So that to that should be added the total throughput, if you are using the Plant figure of your production within that area, to that should be added the gas cap?

A Yes, those totals are just for the crude.

Q That is all, thank you.

THE CHAIRMAN: Mr. Steer?

MR. STEER: No questions.

CROSS-EXAMINATION OF THE SAME WITNESS BY MR. BLANCHARD.

Q Mr. Connell, have you any authenticated figures with respect to peak loads in past years?

A I think Mr. Stevens-Guille will deal with that question, Sir.

Q He will have that information for us?

A Yes.

Q Do you anticipate that a great many of the oil wells that have been good oil wells will eventually become gas cap wells as good as, as productive as the gas cap wells themselves?

A It is quite possible that they will. There are some wells now, for instance Foothills 11 has a gas/oil ratio of 25,000 cubic feet per barrel and it is probably a better gas well than it is an oil well.

Q There will gradually be more of them, I take it.

A That is correct. It will all depend on the economics of producing those wells, if they are kept on as gas cap wells or not.

Q So as time goes on and they do not produce the oil, we will find they are very good gas wells, a great many of them?

A A number of them will be.

Q Those have not been taken into consideration in your gas cap estimate at all?

A No, we carried those wells down to 75 pounds per square inch tubing pressure in our oil area.

Q Would gas wells of that character, that is wells that have become as good as the gas cap wells for the production of gas, will they be of great assistance in relieving the peak load situation?

A Some of those wells probably will be of great assistance.

Q Has that been taken into consideration, do you know, in arriving at these peak load figures, that is as to the time when you will not be able to meet the peak load?

A In making my extrapolations of course they are based mainly on 25 barrels per acre per day withdrawal and then as to the gas the figures are carried down as far as it was considered economical to produce that gas. So some of that gas is considered to be produced, down to 75 pounds per square inch operating tubing pressure.

Q Then taking your computation where it is down to 10 barrels a day of oil production, wells of that character may still be very good gas wells?

A Oh yes.

Q And produce at a high rate?

A Yes.

Q So that the fact that they are down as uneconomic as oil wells does not affect their value as gas wells?

A That is quite true, that is why we carried, - why we had two, one of ten barrels per well per day and one of ten barrels per day with 75 pounds.

Q And that accounts for your very high figure on the 75 pounds?

A Yes, and it also depends on the uneconomic production from those wells.

Q Now I do not know whether this morning, while I was out, whether you brought your estimates down to January 1st, 1945 or not?

A No I did not.

Q I wonder if you could do that without any trouble?

A If you will follow the table on page 2;

Madison Compressor Station No.I: Estimate for the crude oil wells, gas at 75 pounds, to ten barrels per day, 176 as at January 1st, 1944; as at January 1st, 1945 it will be 161.5 billion; actually making this calculation I used 176.2 less 14.7 and the gas cap in the same area 238.9 minus 8.4, being 230.5.

Q MR. CHAMBERS: That is 230.5 instead of 239?

A As of January 1st, 1945; that is a total 392.

MADISON COMPRESSOR STATION No.3

43.4 and 5.4,38 even. Gas cap 3.6 minus .3, 3.3 or total

41.3.

Gas and oil Products Plant, 27 even minus 3.9, - 23.1.

Gas cap 27.3, minus .8 , - 26.5, Total 49.6.

British American Plant, 44.1 minus 6.5, - 37.6. Gas cap 31.2 minus 1.2, - 30 even, or a total of 67.6.

The total 290.7 minus 30.5, - 260.2.

And the gas cap 301 minus 10.7, - 290.3, making a total of 550.5 billion.

Now from the crude oil well of ten barrels per day, 105.7 minus 14.7, - 91.

The gas cap will be the same as above giving a total of 321.5.

In the Medison Compressor Station No. 3 33 even, minus 5.4, - 27.6.

Gas cap 3.3 as above, giving a total of 30.9.

Gas and Oil Products Plant 19.7 minus 3.9, making 15.8.

Gas cap 26½ as above, a total of 42.3.

British American Plant 28 even, minus 6.5, - 21.5, and the gas cap 30 as above, making a total of 51.5.

Total 186.4 minus 30.5, - 155.9.

Gas cap 290.3 as above, making a total of 446.2 as of January 1st, 1945.

Q MR. BLANCHARD: Thank you very much. Now then in

arriving at your estimates from the crude oil area, you used the decline curves, and the oil production and the gas production and tubing pressures?

A Yes.

Q Have you done that for each well?

A That is correct.

Q And then from that you have extrapolated your curves to get your results?

A That is correct.

Q Did you have any difficulty in extrapolating the curves with respect to the tubing-head pressure?

A We had less control, we had less a control over the tubing pressure than any one of the other factors.

Q And what, about what percentage of the 250 wells did you find that you could reasonably arrive at a proper decline curve, the extrapolation of the curve for individual wells?

A Somewhere in the order of 25%.

Q So that there were only about 25% of the cases that you could satisfactorily to yourself extrapolate your curves?

A Yes, the other ones had to be estimated from information which we have and it was necessary to make that estimation, to know whether this gas is available and at what pressure. That does not necessarily mean --

Q What you did then was to take a group of wells or some wells near by that gave you some similar information?

A That is correct.

Q And estimated from that?

A Yes.

Q Not entirely satisfactory I suppose?

A Well it was not as satisfactory as it might be but it was necessary to make the estimate.

Q Yes, I mean there is room for a fair amount of error in that method?

A There would be, - the greatest error would come from the bottom, that that well would not be able to produce into the lime; so long as the pressure, so long as the operating tube pressure was well above the gas gathering line pressure it would not matter.

Q Is it, is the decline curve method which was employed by you as easy of application where you have a controlled production of wells under the Brown Plan as it would be if wells were producing to their full capacity?

A I think possibly/seeing that we have a uniform withdrawal rate from these wells, we should have reasonably good control over these decline rates. If the production rate was controlled by a seasonable demand I do not think we would but where we have a fairly reasonable withdrawal rate, as we have under the Brown Plan.- - - -

Q What I had in mind is that when a well reaches the point where it cannot fulfil its allowable and goes on a curve related to its capacity, there would be a different decline, would there not?

A I do not, - a number of wells in the Valley, there is a voluntary reduction in the production rate by the operators. There may be wells close to the edge water or wells where the gas-oil ratio has declined too rapidly.

Q My information was that the decline curve method was not used where wells were under proration, it was difficult then?

A   Well I think it can be used under a plan similar to the Brown Plan where the withdrawal rate is fairly uniform.

Q   Now there is no doubt that the material balance method can be used in oil areas providing you know what the true reservoir pressures are?

A   It can be used providing you know the true reservoir pressure. It can be used to calculate the total amount down to a specific limit but it would not give the answers we require nor the information we require. It would not give the rate.

Q   No, I quite agree; what it shows is whether the gas is there or not?

A   That is correct. It does not show whether it is available or not.

Q   It cannot show whether it is available under the conditions existing for producing wells?

A   That is correct.

Q   That is another question?

A   Yes.

Q   But it will show whether the reserves of gas are there, that is the minimum reserve?

A   Yes, if you have sufficient reservoir pressure data available.

Q   Then you know the gas is there in case you can produce it?

A   Yes.

Q   Now then the reason I think you did not apply the material balance method was that the true gas reservoirs were difficult to ascertain?

A   True reservoir pressures you mean?

Q True reservoir pressures I mean?

A Yes, they could not be obtained in a short length of time, a reasonable time.

Q They should be shut-in, the wells should be shut-in for a considerable length of time?

A Yes, sometimes it takes up to a month.

Q Up to a month. Now I think there were some wells shut-in for a period of time, for longer than a 24 hour period, that is there were shut-in tests, were there not?

A In November and December 1944 there were built-up pressure tests taken at 17 wells in the B.A. Oil area, that is correct.

Q And what was the result, - for how long were they shut-in and what was the result?

A Oh, those periods varied from a maximum of 28½ or 32 days was the maximum I see here and there is one as low as 7 days and the estimated reservoir pressure calculated using the Muscat formula was approximately 200 pounds higher than the 24 hour shut-in bottom hole pressure.

(go to page 1144)

Q That was for a period of how many days?

A One is as low as three days and another one to 32 days.

Q So that the reservoir pressures in weighted wells gradually equalized until the bottom hole pressure of wells gauged at 200 pounds higher?

A Yes, it is not known whether that is true of all wells in that area. That is the average of those 17 wells.

Q That was probably some indication of the final true reservoir pressure in the oil area, is it?

A It is difficult to say. It might be something on that order. We would have to have more information.

Q It would be under rather than over?

A Not necessarily.

Q In some areas it might not rise to that extent?

A In some areas it might be less and in some greater. It would vary with the permeability of the individual wells.

Q Then as a result of the basis of those figures did you make any estimate using the material balance method?

A Yes, I have some estimates here. I believe Dr. Katz has checked them. We used Dr. Katz' figures as shown in his supplementary report and added 200 pounds per square inch. The gas reserves down to 250 pounds per square inch in the reservoir as of January 1st, 1945 would have been 284 billion cubic feet gas reserve down to 350 pounds, would be 244. Now in Dr. Katz' estimate no allowance was made for the increased pressure that we might obtain from drilling new wells in the north end, so in north Turner Valley reservoir

pressure after an allowance for new wells could quite easily be three to four hundred pounds higher than the figure Dr. Katz used in north Turner Valley.

Q I think he indicated that in his table in his report?

A That is correct.

Q Although he did not use the higher figure he indicated that he thought that would be the case. Then if Dr. Katz had assumed that the reservoir pressure when shut in for a period of, say thirty days, would rise very materially you would expect that he would reasonably find the abandonment pressure at a higher figure or value than the 250 pounds bottom hole pressure. I mean, for the reason that he would not expect that gas to come in to the well rapidly?

A That is correct.

Q So that you have figured this down to 350 pounds?

A 350 pounds.

Q Making allowance for that fact?

A Yes allowing for 200 pounds average increase.

Q Well then perhaps you could give us your figures for each area based on the material balance method and based on this 200 pounds additional reservoir pressure?

A In the B. A. area 52.1.

Q Have you that information in such form that it can be filed?

A Yes, I can file this.

Q Without depriving you of your own copy?

THE CHAIRMAN: Perhaps it could be read into the record and copies furnished tomorrow if satisfactory.

MR. BLANCHARD: Yes that is.

A B. A. 52.1, Gas and Oil Products, South Royalite, 51.4; North Turner Valley 109.7; South Sheep Creek 30.7.

Now in the North Turner Valley, allowing for new wells at 300 pounds per square inch gas reserves at 350 pounds, would have been calculated as 129.4 billion cubic feet.

Q That is all, thank you.

THE CHAIRMAN: Have you anything Mr. Steer?

MR. STEER: No.

HENRY LE MARCHANT STEVENS-GUILLE, having been duly sworn, examined by Mr. Chambers, testified:

Q Mr. Stevens-Guille, you occupy what position with the Madison Natural Gas Company?

A Field Superintendent.

Q Now would you please outline in a few words your training and qualifications?

THE CHAIRMAN: Is that not all on record, Mr. Chambers, from the hearing in May. That is my recollection.

MR. CHAMBERS: Yes, I will not bother with that.

THE CHAIRMAN: And it is also of Mr. Ralph Davis and I forgot about it at the time.

Q MR. CHAMBERS: Now Mr. Stevens-Guille, you prepared two reports called M 2 revised and M 2 A?

A Yes sir.

Q Now before we have those marked would you please explain what they are and the differences. By the

way for the purposes of the record I should say that the M 2, that is distributed to the interested parties, we are not introducing that or using it at all for the reasons explained in the revised M 2 except for the map. If you wish to put the map from that into M 2 revised you can throw the other away.

DR. BOOMER: The tables are not to be used?

A Just the map. The object of preparing M 2 and M 2 A was to determine what proportion of the reserves as had been estimated in M 1 by Mr. Connell -

MR. CHAMBERS: That is Exhibit 44?

A Exhibit 44, yes, could be used economically in the market and as will be remembered Mr. Connell in M 1 estimated his reserves on two separate bases. The first set were down for crude oil wells, to an assumed well operating pressure of 75 pounds or to 10 barrels production per day whichever of those two conditions was reached last. And the second set of conditions that Mr. Connell hypothecated for the operation of crude oil wells was down to an average daily production of ten barrels. In both cases he took his gas cap reserves down to the same condition of 100 pounds. In report M 2 revised deals with the first set of those conditions and report M 2 A deals with the second set of those conditions.

Q MR. CHAMBERS: Probably this would be a good point to mark those as Exhibits.

DOCUMENTS M 2 REVISED MARKED AS EXHIBIT 47 AND M 2 A MARKED AS EXHIBIT 48.

Q MR. CHAMBERS: Now dealing with Exhibit 47, I am going to suggest it will not be necessary to read Exhibit 48, much of the wording is the same?

A It is set out in the same system as 47, the only difference is in figures and dates and in one or two minor cases the wording had to be altered to suit the figures.

(Go to Page 1149)

MR. CHAMBERS: Would it be satisfactory to the Board if Mr. Stevens-Guille reads Exhibit 47?

THE CHAIRMAN: I will leave that entirely to you, Mr. Chambers.

Q MR. CHAMBERS: I will leave it up to you, Mr. Stevens-Guille.

A Shall I read Exhibit 47 and then we can see when we reach that stage.

Q THE CHAIRMAN: Where the difference arises?

A Yes. To save time. Exhibit 47, turning over to the second page after the Index, there is a foreword which explains why the original report was revised and this second copy submitted in its place. I do not propose to read that. It is self-explanatory. The only difference I would note is that the difference between the two reports is small, a matter of 6 billion in 355 billion. Therefore, we felt that it would be more helpful to everybody concerned if we submitted the original report at the time it was read, and this second and revised edition is a revised edition prepared as soon as we could correct certain mechanical errors that had occurred in the first one. So turning now to page 1, to the Economic Marketable Reserves.

<u>Introduction</u>

In Report M-1, Exhibit 44, "Estimate of Limestone Gas Reserves in Turner Valley", by Mr.Gordon Connell, he presented a geological report covering the total gas reserves in the field, finding these totalled 591 billion cubic feet as from January 1st, 1944 down to 75 pounds operating tubing pressure, or ten barrels per day production,

whichever condition was reached last. This represents the total volume of gas in the formation down to the operating conditions quoted and not the volume of gas that will be available for delivery to the market.

As I have just explained that is the reason for Exhibit 47, which I am now reading, being prepared to take those estimated reserves and to determine what proportion of them would be available for market purposes. That is stated in the next sentence.

The purpose of the present report is to show what proportion of those reserves are economically marketable.

To derive the marketable reserves from the total reserves, consideration had to be given to a great many factors; the most important of these being the estimated operating conditions of wells from year to year, from which the most suitable operating pressures for gas gathering systems were determined, which in turn gave the volume of gas that would be processed by the several plants and the volume that would be flared as uneconomical to gather. Of the volume gathered only a proportion is available for sale in the market, certain percentages being used for field operations, including blow downs, lease fuel, fuel to heat gas gathering lines, plant fuel and shrinkages in processing the gas in absorption and scrubbing plants to remove gasoline and hydrogen sulphide. At the present time some gas is also used for fuel at drilling rigs and for kicking-off wells to bring them into production.

After giving due consideration to all the above

factors the conclusion has been reached that a total residue gas volume of 361 billion or a wet gas volume of 448 billion, which is 76% of the total reserves estimated by Mr. Gordon Connell, can be economically delivered to the market.

The distribution of these total reserves is as follows;- and the volumes quoted are in Billion cubic feet, and were applicable to the residue gas and the wet gas equivalents have been given in the total.

Q MR. CHAMBERS: Mr.Stevens-Guille, these figures are as of January 1st, 1944, are they?

A Yes. The volume flared and used on the lease is given as being 14% of the total reserves. The volume flared as residue gas in 1944 or used for drilling fuel in 1944 and in 1945 is estimated 9.8 on a residue basis and 13.1 on a wet gas basis, or 2% of the total. The actual marketable reserves are estimated at 361.3 billion cubic feet on residue gas basis, and the equivalent in wet gas of 448.3, or 76% of the total. The remaining reserves or the balance, as will be developed later, will not be produced to the market according to the estimate that we have made here amounts to 47 billion on a wet gas basis or 8% of the total, and those figures add up to 591.6 billion wet gas basis, which was the figure given by Mr.Connell in his report down to the operating conditions that we are now discussing.

At the average estimated market this will provide a source of supply for some 31 years. I might note there that while we have used in this report the estimated market for the whole period, the figures are not given themselves in

the report. They are submitted seperately in Report M-4.

In the last six years, however, the capacity of the wells will be insufficient to provide for peak loads, and an auxiliary source of supply will therefore be required from about 1969 onwards. The question of peak loads is touched on again later, and at that time I will explain further how we arrive at these figures covering the peak load requirements.

It will be recalled that in Weymouth's report certain estimates of the reserves in the field were given. These were based on the assumption that the volume of gas from crude oil wells in the central and north end would decline at the rate of 10% per year on the declining volume and that both gas cap and crude oil wells in the south end in the areas served by the British American and Gas & Oil Products plants would decrease at this same rate. The reserves for the Royalite gas cap were extrapolated from a graph showing the relationship between actual well operating pressure and cumulative gas volume produced.

In another report M-3, a comparison has been set up between the reserves originally estimated by Weymouth in the report that I have referred to in the previous paragraph, and the reserves that would be estimated using his method, but using more modern production data, and also the estimates as given in this report, Exhibit 47, and also in Exhibit 48. That report will be dealt with after these reports.

The economic market reserves presented in

this report have been estimated by a different method. In another report, M-3, the reserves have been computed on the method used by Weymouth but starting from 1944 production data.

The general method of determination of the volume of gas that could be delivered economically to the market was to review in turn the rates of volume and pressure declines for the wells connected to each of the three gas gathering systems, using for this purpose the data presented in Report M-1, Exhibit 44, by Mr. Connell.

It might be useful if I elaborated a little further on what that rather simple statement involved in the way of work. You have seen in exhibit 44, Mr. Connell's report, the estimates he made for each year for each well. Those estimates were taken and were posted or grouped under each of the gas gathering systems, which I will indicate on the map behind me in a moment, and an analysis was made for each year of what the estimated volume would be against any given operating pressure for a gas gathering system. Taking, for example, the Madison Gas gathering system connected to Compressor Station No. 1, several pressures for each year were investigated and the volumes that would be gathered, and the volumes that would be flared were determined, and with those figures in front of us, the decision was made as to what the most economical operating pressure for the gas gathering system would be in our judgment, and that was done in turn for each gas gathering system for every year that

has been reviewed.

Now the three gas gathering systems are the Madison, British American, and the Gas & Oil Products.

As an attachment in the envelope in the back cover of the original report M-2, there was a map showing these gas gathering systems by having the wells coloured according to the system which they entered into, or in another colour if they entered no system at all. Now, for convenienve we have reproduced that map on a larger scale and we have it on the wall here. The only difference has been the system of colouring. Instead of just colouring each well as a small dot we have coloured the legal subdivisions so that it is more easily seen at a distance. Starting in the North we have coloured black solid for the Foothills oil wells and black hatch for the gas cap wells. The Madison system tributary to Madison Pressure Station No. 1, just at that point - -

Q THE CHAIRMAN: Perhaps you had better indicate that and detail it on the record.

A Give the map reference?

Q Yes?

A Section 6 of Township 20, Range 2, West of the 5th. It will be noted that there was in this area, that there are in this area certain wells coloured orange. Those are the wells which are not connected to the system, due to their operating pressures being too low to enter against the line pressure. Travelling Southward the next gas gathering system is that tributary to Madison Compressor Station No. 3, which is situated in Section 7, Township 19 Range 2, West of 5. That system is coloured

blue and it will be noted that there again there are wells coloured orange in the same area which are operating at too low a pressure to enter the gas gathering system.

Still moving Southward the next gas gathering system is that of the Gas & Oil Products, which is coloured green for the crude oil wells, and green hatch for the gas cap wells. And the Gas & Oil Products plant is located in Section 4 of Township 19, Range 2, West of 5. And again in that area there are certain wells marked orange which are operating at too low a pressure to enter their system. Moving now to the extreme South of the field we come to the British American Gas gathering system.. There are two systems, one operating at a higher pressure than the other, and the higher pressure one is marked red for crude oil wells and red hatch for gas cap wells, and the low pressure system is marked yellow and only gathers gas from crude oil wells. The B.A. gasoline plant is situated in Section 22, of Township 18, and the low pressure compressor station gathering gas from the wells coloured yellow here, would be located in Section 17. Is that right, Mr. McCutcheon?

MR. HARVIE: The low pressure compressor station?

A In Section 17?

MR.HArvie: Section 20.

A Section 20, of Township 18, Range 2, West 5. There again there are one or two, but noticeably fewer, because of the lower operating pressure of the oil system of the B.A. area, the low pressure system, wells coloured orange because, at any rate, at the time that this map was prepared, they were not entering any gas gathering system. They may

have been able to gather it in some cases since.

Turning back now to Exhibit 47, page 3 and the top paragraph.

Each gas gathering system presented problems in estimating of its own, therefore they will be considered separately, starting with the largest, the Madison system. A map of all the producing wells in Turner Valley, with the wells colored according to the Plant to which their gas is delivered for processing was appended at the end of the report originally issued as Report M-2.

1. <u>Madison Gas Gathering System</u>

The Madison gas gathering system comprises two compressor or boosting stations, #1 and #3, each with its system of gathering lines, which serve the North and Central areas of the field respectively.

A. <u>Madison Compressor Station #1</u>

Compressor Station #1 is at present operating at 240 pounds per square inch gauge suction pressure but this pressure will be lowered to 200 pounds per square inch gauge in the near future when certain alterations now in progress are completed. The estimated volumes and operating pressures for the wells connected to this Compressor Station, as given in Mr. Connell's report, were analyzed year by year and the projected suction pressure of the system lowered from time to time as the estimated declining operating pressure of the wells indicated was necessary, if the number of wells flared were to be kept to a reasonable figure. It is appreciated that what is considered "reasonable" is a matter of judgment and in this

connection it must be borne in mind that the pressure of the whole system must be reduced to that necessary to permit the well with lowest operating pressure to enter, or the gas from that well must be flared. It is not economical to depressure a large volume of gas and reboost it, in order to gather a relatively small percentage of the total. On the attached summary, Table 1, the volume connected, proposed suction pressures, together with estimated volumes that will be flared, are shown for the period 1944-1964 inclusive.

I would like you to turn now to Table 1. Now as I mentioned a little time ago, the position each year was very completely analyzed before the assumed suction pressure which is shown in Column 1 of Table 1 was arrived at. So there is no question of pure hit and miss and the judgment which I have referred to just now was made with all this information in front of us. The operating pressure was in nowise pulled out of the air or based merely on the data we have summarized here. If you will follow through to column 5A and 6, you will note the amount of gas that we estimate will be flared as shown in Column 5 as our acreage m.c.f. per day per year and then the total for the year, the m.c.f. per year in Column 5-A. And then in Column 6 is percentage of the total gas that it is estimated wells connected to the system will produce in that year. If you follow down, you will see for the years 1945 right through to 1952 inclusive the percentage we have indicated will be flared if the suction pressures we have proposed to use range so low as 5 per cent even to a maximum of 8.2. Now we found that on investigating lower suction press-

ures than that we finally assumed that very little decrease in the amount that would be flared would occur, even if suction pressures considerably lower than those shown in Column 1 were to be used and that is what we mean when we say: "Reasonable judgment had to be used". Now going back to Column 1 again, it will be seen that by the year 1950 the suction pressure will have gone down to 100 pounds. In 1951, 80 pounds. In 1952, 60 pounds. From then on we have shown the suction pressure of 60 pounds for reasons that are covered in the next paragraph of the report.

Q MR. CHAMBERS: Mr. Stevens-Guille, as I understand it in order to reduce the pressures it means installing more compressor equipment.

A That is correct, Sir. Then before leaving Table 1, I point out one more point in Column 5A and 6 that the amount flared does increase from the year 1952 onward, being 12 per cent in 1952 and rises to as high as 90.2 per cent in the final year of 1964. But column 5 shows that the volume flared will not increase but remains relatively constant at between 3 and 5 billion cubic feet per day. And our investigation showed that the installation of additional compressors would be large to gather and deliver to the market that relatively small volume of gas.

Going back now to the narrative where we left it on page 3 at the bottom paragraph, in arriving at the lowest suction pressure that it would be economical to use, several factors had to be taken

into consideration; such for example as the probable lowest operating pressure of crude oil wells before abandonment due to small volume of gas and oil produced, the increasingly rapid rise in brake horsepower required per unit volume pumped as the suction pressure approaches atmospheric, and the number of units required to meet peak loads at the suction pressure selected. The conclusion reached was that the lowest suction pressure advisable was 60 pounds per square inch gauge. That is purely a matter of economics. We could go to a lower assumed suction pressure quite easily from a mechanical point of view but the cost of the installation would rise rapidly and also we would have to take into consideration the fact that the crude oil wells will reach abandonment where the gas cap has still got a very substantial pressure. We would therefore have installed a large volume of equipment to take out relatively small quantities of crude oil gas. We would have had equipment idle again for a period of years when the market was once again largely supplied by gas cap gas only. It is our judgment that 60 pounds is the proper figure to take.

Going back to the narrative and the second paragraph on page 4:

For several years there will be available to the market residue gas from crude oil wells in excess of its requirements, and arrangements are being made to store this in the Royalite gas cap in the vicinity of Compressor Station #1 and also

in Bow Island. The object of storing it in Bow Island is threefold:-

(a) To keep the investment in equipment to a minimum, compressor equipment for returning gas to the sand being already installed and idle at Bow Island.

(b) To increase the reserve at the far end of the Canadian Western Natural Gas Company's transmission system as a safety factor in case of line trouble.

(c) To provide time in spring and fall for compressor cylinder changes to be made at Compressor Station #1.

There is a point that could probably be usefully explained now. During the winter the full capacity of the compressors at Compressor Station #1 will be used for boosting the wet gas through the Plants and deliver it to the market. But when the load falls during the summer months, quite a high proportion of that equipment is idle and the present plan is to use that idle equipment to return the gas to the limestone formation. That is the excess gas from crude oil wells to the limestone formation and store it there. The object of that arrangement is obvious. It will result in a minimum outlay for equipment, the gathering equipment required. In addition of course to the input line system radiating from the plant to the wells in which gas will be injected will only amount to high pressure compressor cylinders in place of having to buy a whole gas engine drivên compressor unit. As everybody knows there has already been between

12 and 13 billion cubic feet put back into the sand at Bow Island and the compressors that were installed for that purpose are still there and at the present time are being put in condition to operate again. That stored gas provides a very sound source of supply should for any reason there be interruptions in the transmission lines from Turner Valley to the South of the Province.

Going back to the narrative then. In summer months up to fifty per cent of the installed compressor capacity is at present idle due to small market demand. To keep the total installation of compressor equipment at Compressor Station #1 to a minimum, it is planned to convert two units from wet gas booster service to residue gas return service during these months by changing from low to high pressure compressor cylinders. By putting gas back into Bow Island in spring and fall the overlap in capacity requirements of both the wet gas booster and the residue gas return services at Compressor Station #1 will be provided for. That covers a period like the present when any day we may still meet with a peak demand from the Canadian Western system. We have experienced in past years, even in recent times, 30 below zero weather in the end of March and any weather sub-zero at the present time would call for a peak demand from Turner Valley. And the opposite happens again of course in the Fall. We can as early as September or October get storms which, while possibly not so severe, have the same effect in requiring a peak delivery of gas because

people do not have storm windows on and generally are unused to seeing snow.

Going back to the narrative. The input wells selected are as follows:

Royalite #17

McLeod #4 and

Midfield #1.

All these wells are in the vicinity of the Compressor Station and all were originally large producers. The input line system to these wells was laid before freeze-up in 1944.

Q MR. CHAMBERS: Can you give us the legal description of each of those wells?

A Yes, the wells selected are all in the vicinity of Compressor Station #1 in order to keep the investment in the input lines at a minimum. Royalite 17 is in L.S.D. 13 of section 6, township 20, range 2, W of the 5th. McLeod 4 is in L.S.D. 16 of section 1, township 20, range 3, W of the 5th and Midfield #1 in L.S.D. 9 of section 1, township 20, range 3, W of the 5th. They are all within a mile of Compressor Station No. 1.

(Go to page 1163)

They were also as stated here, good producers of gas, for there is every reason to believe that they should be wells with a high capacity to take gas back. Therefore we hope that these will be the only three wells that may have to be used.

From 1945 to 1955, a period of eleven years, residue gas will be stored in either Bow Island or Royalite gas cap. The amount of residue gas stored in these two places is the total of the gas to be stored from Madison gas gathering system and Gas & Oil Products gas gathering system, the B.A. having made their own provision to store gas in the South end of the field.

The amount to be stored in Royalite gas cap is this total less the amount stored in Bow Island. The amount stored in Bow Island is determined by the number of days storage is necessary, which is calculated from a load factor diagram, and it has been assumed that if Bow Island is placed in operation in any one year it will run throughout the summer season for the operation to be economic; otherwise the Gas Company would not keep operators ready to run that station and if no gas is stored at all they will have to have those operators there and the station in condition to operate.

Gas is then estimated to be stored at 4,200 M.C.F. per day for these days. After 1948 storage will no longer be necessary in Bow Island as the compressor installation at Compressor Station No.1 will have sufficient capacity to handle the smaller

volumes to be stored.

The assumption is made that as long as the cumulative amount withdrawn is less than cumulative amount stored for any period, then the allowable will remain static and hence the Brown allowables.

I should have had in there "Should also remain static". With reference to the gas cap in the Royalite area where the storage is to take place. It is of course a pure assumption and will in actual fact not be precisely true. The gas cap stretches for a considerable distance away both North and South of the in-put wells and without doubt the gas re-pressured in these in-put wells will not effect the most distant gas cap wells but it is merely mentioned here for the purpose of carrying out our computations because in figuring the load-up for each year, how much crude gas there is available, how much the market will consume and therefore how much supplementary gas would have to be withdrawn from the gas cap to supply the market, we had to make some assumption as to what the Brown allowable of the gas cap wells would be so that we could get the proper sharing positions between the crude oil wells and the gas cap wells to arrive at the amount which would be stored in each year and not delivered to the market and this assumption should not be used for any other purpose than that for which it was made here.

When it occurs that more has been withdrawn than stored in any one period (as shown

in Table 2) then the allowable is decreased using the relationship shown in Graphs 2 to 5, 76, 77, 78A and 79A, in Appendix A, Madison Report M-I, that is Mr. Connell's report and was exhibit #44. These graphs show bottom hole pressure versus cumulative production and bottom hole pressure versus allowable, based on equivalent acreage obtained using allowable for 1945 and a weighted bottom hole pressure. Those were the curves which Mr. Connell referred to and was questioned on this morning.

The allowables as estimated for Royalite are shown in Table 3

In 1958 the point will be reached when the Brown allowables of gas cap wells will be insufficient to meet market requirements. It was assumed that the Brown allowables would then be discontinued and withdrawals equal to requirements permitted, such requirements to be withdrawn proportionally from the Royalite, British American and Gas and Oil Products gas cap wells on the basis of equivalent acreages and weighted average bottom hole pressures, estimated for each year after deducting the withdrawal of the preceeding year using the graphs mentioned above, that is the one which I referred to a few minutes ago, graphs 2 to 5 and so forth.

It is estimated that the market can be supplied until 1968 by the gas cap, but by that year the capacities of the gas cap wells will have decreased to the point at which peak winter loads can

no longer be met. An auxiliary source of supply will have to be drawn on to an increasing extent from that year onwards.

Of course I might make a point there, the fact that a time will come when the gas cap wells will not be able to supply the peak demand to the market has in no way been changed except in date by any of the schemes which have been installed, subject to this Natural Gas Utilities Act being passed, just an event which was bound to happen at some date or another.

Alternatively the market could be fully supplied for some time longer by drilling new wells in the gas cap on the undrilled acreage known to be on structure and there appear to be some six favorable locations. Productivity, but not, of course, the ultimate volume of gas, could also be increased by acidizing the wells already drilled. Whether or not it will prove economic to carry out either or both of the above development operations will depend on the situation at the time and the auxiliary source or sources of supply. It might pay to take the gas out of Turner Valley faster than for Turner Valley to be the sole source longer; or, on the other hand, it may pay better to produce the gas over a longer period but with smaller investment, gradually increasing the facilities to supply the balance from another source. The data upon which such a decision would be made is not available today, some twenty years before it will have to be made. It is believed it will not alter reserves sufficiently, if it is ignored for our present purpose.

From 1969 onwards analyses were made annually of the maximum capacities of the Royalite and British American gas cap wells; -our estimates would indicate that the Gas and Oil Products **gas** cap wells would no longer be producing, that is why they are not mentioned together with the Royalite and British American gas cap wells, - by use of graphs, report exhibit 44, showing the relationship of top hole pressure versus capacity in M.C.F. per day. These curves appear as graphs 6 and 10 in Appendix A of Mr. G. Connell's report. From a study of load conditions, the volume of gas which at peak loads was beyond the capacity of the gas cap wells to deliver was determined. This quantity, which of course increases year by year, would have to be supplied from another source, as previously pointed out.

In 1974 it was found that the total volume that would be delivered was 7,449,000 C.F., which is approximately 60% of the market of 12,527,000 C.F. It was arbitrarily assumed that operations in Turner Valley would be closed down on December 31st, 1974. It will later be shown that operations in the area served by the British American gas gathering systems will terminate on or before 1974 and that the reserves in the area served by the Gas and Oil Products gas gathering system will terminate on or before 1966. It might or might not be economical to continue to produce the Royalite gas cap after 1974, but the additional gas taken out would not appreciably alter the economic marketable reserve, which is the subject of this report.

Now if the gas cap was to be abandoned, as has been suggested after this year, December 31st, 1974, our estimate shows that the weighted bottom-hole pressure of the gas cap, of the Royalite gas cap at that time would be 195 pounds and we also show that we would leave underground, down to the 100 pounds which was the operating condition predicated by Mr. Connell in his report, a matter of 28.1 billion cubic feet on a residue gas cap basis or 33.2 on a wet gas basis. That is shown in summary B, which is one of three summaries reconciling this report with Mr. Connell's report and from those summaries we obtain the shortened form of reconciliation shown on the top of page 2 which I went through as we read the narrative.

Now one other point being touched on by witnesses which have preceded me, and that is that it is purely arbitrary, this time ahead, to see whether or not the operation would continue after 1974 and as we have just seen it only has an effect of some 28 billion of the final reserve. Clearly if no other source of supply was available for Calgary it is probable that the operation would be continued beyond that point but if on the other hand one or more suitable sources are already proven it is very questionable whether it would be economic to carry it on.

Now going to the second gas gathering system,or "B" the Madison Compressor Station #3.

The present suction pressure at this station is 60 pounds per square inch gauge, and it is planned that this pressure will be lowered as the

volume delivered by the wells connected decreases, keeping the station fully loaded as long as this is possible. With a discharge pressure of 375 pounds per square inch gauge, a suction pressure of 40 pounds per square inch gauge would give a ratio of compression of 7.2, which is the limit of single stage operation. An analysis of the estimated operating pressures and volumes produced, showed that little gas would be flared under these conditions of operation, therefore they appeared to be a suitable basis for estimation. The volumes available and the estimated amount flared are given in Table 4.

And turning to Table 4, the assumed suction pressure is shown in column 1. This is at the present time, 1945. This is for 1946 but the volume of gas connected will decline by 1947 to where the horse-power, that is the number of compressors already installed, can operate from a 50 pound suction pressure without being over-loaded, therefore it is proposed that that will be the proper operating pressure for 1947, 1948 and onward by the same method the operating suction pressure of 40 pounds has been arrived at.

Turning, travelling across rather, to column 5, 5A and 6, the volumes and the percentage of gas it is estimated will be there, are shown. Some of the percentages are rather large in column 6 but a glance at column 5 will show that the volumes concerned are not very big and in the final years the amounts are very small indeed.

Going back now to the top of Page 7. There are three gas cap wells connected to this station, Sterling Pacific #1, 2 & 3. From 1945 to 1949 it was assumed that no withdrawals would be made from these wells as the crude oil gas connected would provide a full load factor to the Compressor Station. From 1949 to 1953 estimated withdrawals were based on keeping Compressor Station # 3 loaded. By 1954, however, withdrawals to keep the station loaded would have exceeded the estimated allowable; but the withdrawals were kept to the estimated allowables until 1958 when, as previously described, the gas cap allowables for the whole field were insufficient to supply the market and it was therefore assumed that operation under the Brown plan would be discontinued. In 1958 and 1959 withdrawals were based on the method described under Compressor Station #1. By 1959 the volume had declined to 193,000 Mcf. per year, or 530 Mcf. per day, therefore it was assumed that the gas cap wells connected to the station would not be operated after December 31st, 1959.

Of course, the object in commercial practice is always to keep your compressors loaded to 100% of their capacity and that is what we have aimed at doing here to make the utmost use of the horsepower installed. We have suggested that between the years 1954 and 1958 when the rest of the gas cap wells in the field can supply the market that the Brown allowable might still be in force and there would be insufficient gas connected to compressor station #3 to provide a full

load, but it well might be that the Brown allowable for gas cap wells anyway might have been lifted before that date.

On Table 5 the total crude oil gas to be handled by the Madison gas gathering system is shown from 1944 to 1964 inclusive.

That is, the amount to be handled by compressor Stations # 1 and #3 have been collected and shown on the one table for convenience.

That completes the discussion on the Madison #2 gas gathering system and we go now to the second one, British American Gas Gathering System.

The second largest gas gathering system is that of British American, which serves the south end of the field and is composed of two parts, the original high pressure system delivering under well pressure to the gasoline plant operating at 150 pounds per square inch gauge; and a compressor station, installed in 1944, to gather gas from the low pressure wells on the western flank of the field, at a suction pressure of 10 pounds per square inch gauge, boosting it to 170 pounds per square inch gauge in order to put it into the high pressure system for delivery to the gasoline plant.

For the purpose of this report it was necessary to make the following assumptions:

It will be understood, of course, that as we did not have first hand knowledge of all the factors in the British American system, we have had to assume that certain facts would be true and our analysis of the situation is only correct insofar as our assumptions

are correct. We are not in any manner of means saying that our assumptions are correct nor are we venturing to the operators of the system how it should be handled. Merely to make our picture of the story complete we had to assume something and these appear to us reasonable figures and facts.

(a) The operating pressure of the gasoline plant would remain at 150 pounds per square inch gauge.

(b) The low pressure station would operate at a suction pressure of 10 pounds per square inch gauge, but had the capacity to operate from 0 pounds per square inch gauge, if desirable.

(c) As the operating pressure of a well became too low to enter the high pressure system, it would be connected into the low pressure system.

(d) That the weighted average pressure of the gas cap would remain constant until the cumulative withdrawals starting from 1945 exceed the cumulative volume stored.

That again is the same assumption as we made in order to be able to handle the withdrawals from the gas cap in the north end, the Royalite gas cap, and work out the sharing position of the different suppliers which I will show later was necessary for the computation of table #8, which is appended to this report.

(e) The Brown formula will not be applied when the total allowables are less than market requirements.

(f) That $2\frac{1}{2}\%$ of the wet gas produced by the wells connected would be used in well pulldowns and blowdowns and 20% of the gas processed consumed in plant shrinkage and fuel.

A. High Pressure System

The high pressure system was first analyzed, and as the estimated operating pressures of a well connected to it dropped to the point at which it could no longer enter this system, it was assumed that it would be connected to the low pressure system and it was accordingly included in that system from that year on.

B. Low Pressure System

The low pressure system was then analyzed and it was found that the station would not be overloaded in any year, even if the gas from wells whose pressure had declined below that necessary to enter the high pressure system were included. Furthermore the estimated data showed that, if the suction pressure were to be maintained at 10 pounds per square inch gauge, only a small volume of gas would be flared in any year. It is our understanding that this station was designed to go to a suction of 0 pounds per square inch gauge, therefore the position appears to be amply covered. These analyses are summarized in Table 6.

Referring then to Table 6. Of course it will be clear that this information is only correct insofar as Mr. Connell's estimate of the operating conditions of the wells is correct. It is based upon it. There might be other viewpoints and other figures produced for the operations in any one particular year or even for all of

the years. The second pressure in this case is stated at the top of the table because it remains constant instead of in column 1 in the case of Madison Compressor Stations #1 and 3 tables and the volume of wet gas that will be flared according to our estimates are shown in columns 6 and 7. It will be noted that they are very small amounts. The rest of the figures I think of that table are self explanatory when they are taken with the foot notes at the bottom.

It is recognized that the assumption that all wells on being unable to continue to deliver to the high pressure system will be turned into the low pressure system, may not be capable of fulfilment in all instances due to the layout of the two systems. It appears possible that the load factor on the low pressure station will be such, that if a well on the end of a high pressure lateral reaches the point in pressure decline where it can no longer enter the high pressure system, that such other wells as there may also be on the same lateral could be turned over to the low pressure system without overloading it.

I believe as a matter of fact an instance of that has already occurred.

It seems probable, therefore, that the assumption is sufficiently accurate for the present purpose. It was also realized that other methods of operation might be followed, mainly the lowering of the plant pressure, either as the volume to be processed falls or following a change in specification of the product; but as the figures indicate that the method selected will insure

the maximum volume being processed in any event, the exact combination of operating conditions used should not alter the estimated marketable reserve figure.

British American installed in 1944 equipment for the following duties:-

(a) Compressors to deliver currently to the Madison Scrubbing Plant a volume equal to their share of the market.

(b) Compressors to return to the formation all excess residue gas over their current market sharing position.

(c) Compressors to gather low pressure gas from the west flank in the south end.

(d) Input lines to:-

Carleton Royalties #1

Sovereign #1

Pacalta #1.

Now a point there to note is that their intention to deliver their share of the market currently to the Madison Scrubbing Plant and to return to the gas cap in their own area in the south of the field any excess residue gas from crude oil wells above their share of the market. That is an important point because it enters into the sharing position later.

In estimating gas cap allowables for this area the same assumption has been made as for the Royalite gas cap, namely, that the pressure of the gas cap as a whole will remain constant as long as the cumulative withdrawals from 1945 do not exceed the cumulative volume stored. When cumulative withdrawals exceed the amount stored, the

allowables are decreased using the graphs mentioned above in the discussion on Royalite gas cap under Madison Compressor Station #1 on page 5. The figures are also summarized on Table 6. It has already been mentioned above that in 1958 the Brown allowables will permit insufficient gas to be withdrawn to supply market requirements, therefore it is assumed that from then on the Brown formula will no longer be applied and withdrawals sufficient to meet market requirements will be permitted as under Madison Compressor Station #1, in section 1,A, on page 5. In 1969, as already mentioned on page 6, the maximum capacities of the gas cap wells were analyzed and the volume of gas which could be delivered to market was determined, which was proportioned between Royalite and British American as previously described. By 1974 the weighted average bottom hole pressure had dropped to 105 pounds per square inch gauge and it was assumed that no further gas could be economically withdrawn.

If the British American Plant is shut down before 1974, other arrangements would have to be made to deliver the gas to the market, or the economic marketable reserve figure as estimated in this report would have to be adjusted accordingly.

A point to notice there, of course, is, that,we are making no statement that the year 1974 will be the year in which the British American Plant shuts down. We had to make some point of cut-off and we have carried our figures out to that year so that any variation from that plan can be easily and quickly estimated.

3. Gas & Oil Products Gas Gathering System.

The last gas gathering system to be discussed is that of Gas & Oil Products, which has one system only, serving the south central area of the field and delivering gas under well pressure to their gasoline plant operating at 80 pounds per square inch gauge.

For the purpose of this report it was necessary to make the following assumptions:-

And of course here the same remarks apply as those given to cover the assumptions made on the British American operations.

(a) The operating pressure of the gasoline plant would remain at 80 pounds per square inch gauge.

(b) As the operating pressure of a well becomes too low to enter the high pressure system it would be connected into the British American low pressure system operating at a suction pressure of 10 pounds per square inch gauge, wherever this was within economic reach. The volume produced by such wells would be small. It was deducted from the Gas & Oil Products reserves but not added to the British American reserves.

That was as a matter of pure over sight and we investigated to see whether we should go back and recalculate in view of that, but we found it would only total a matter of some two billion cubic feet, so it did not have sufficient influence on the answer to make it worth while to go back and insert those

wells in the British American low pressure plant volumes.

(c) If the plant shut down before 1966 the gas would be gathered by British American and Madison in their respective areas.

(d) That 30% of the gas processed would be consumed in gasoline plant shrinkage and fuel. Fuel for the refinery would be included in the market.

With falling load, it might be possible to lower the operating pressure of the plant in future years, but at these lower pressure levels the circulation rate required to maintain efficient recovery of gasoline increases rapidly, therefore for the purposes of this forecast it was assumed that the operating pressure would continue at the present level.

When wells reached an operating pressure at which they could no longer deliver to Gas & Oil Products plant operating at 80 pounds per square inch gauge, it was assumed they would be connected to the British American low pressure station, wherever this was within economic reach. In this way it was found that very little gas would be flared and Table 7 gives a summary of these figures. Clearly at some date within the period it will probably become uneconomic to operate the plant, a check was therefore made and it was found that the British American would have the capacity to gather the gas from the wells in the area served by their systems and Madison gas from wells in the area served by their Compressor Station #3 system when, and if, that eventuality occurred. If the Gas & Oil Products plant ceases to operate, it was

assumed that the gas cap wells now connected to the Gas & Oil Products plant would be connected to Madison Compressor Station #3, simply because this could be done at little cost by connecting the existing gas gathering lines at the Gas & Oil Products plant to the 8" line now used as suction line from that plant to the Gas & Oil Products residue gas booster located at Madison Compressor Station #3. The result of this review made it unnecessary to determine when Gas & Oil Products plant might be closed down, as the gas would be available to the market in any event.

Contrary to the conditions which will exist in both the Royalite and British American gas caps due to storage of gas, the Gas & Oil Products gas cap pressure will continue to decline throughout the period, as it is planned to withdraw allowables currently.

The difference there being that the excess residue gas to market requirements from the Gas & Oil Products area will be stored in the Royalite North gas cap and not returned in the area contributory to the Gas & Oil Products plant, such as is the case in British American.

These gas cap figures are shown with those for Royalite and British American on Table 2. The decline from 1945 to 1958 was estimated using Graphs 4 and 78A.

Those are graphs included in Exhibit 44, Mr. Connell's report.

From 1958 to 1960 estimated withdrawals from the Gas & Oil Products gas cap were based on the same method as that used for Royalite and British American gas cap. From 1961 to 1966 the wells could not meet the allowable

calculated in the above manner, hence their maximum capacity was used, see Report M-1, Graph 9, Appendix A. In 1966 estimated withdrawals had declined to 599,000 Mcf. per year or 1,600 Mcf. per day. The volume available from the wells connected was neglected from 1966 onwards, to Gas & Oil Products, as the volume would by then have become small.

Conclusion

From the considerations outlined above, the economic marketable reserves were estimated to be 361 billion as stated on the first page and as shown summarized in Summaries A, B and C, which will be found immediately following this page.

Tables 1 to 7 inclusive give the detailed figures for the various gas cap and crude oil systems and these figures are carried into Table 8 in which the distribution of the gas delivered to the market, stored or conserved is shown year by year for the estimated economic life of Turner Valley. Table 8 is in the box on the back cover.

THE CHAIRMAN: Mr. Stevens-Guille might be with this at some length so I think perhaps we had better adjourn and we would be better able to deal with it at 9.30 in the morning.

(At which time the hearing adjourned)